



NiSource Gas Transmission & Storage®

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Chad Zamarin
Director – Integrity Management

October 29, 2010

Wayne T. Lemoi
Director, Southern Region
Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
233 Peachtree Street NE, Suite 600
Atlanta, GA 30303

RE: Response to Notice of Proposed Safety Order, CPF 2-2010-1010S

Dear Mr. Lemoi:

This letter is provided on behalf of NiSource Gas Transmission and Storage (NGT&S) in response to Notice of Proposed Safety Order, CPF 2-2010-1010S, which was dated September 30, 2010, and received by NGT&S on October 5, 2010. This letter is intended to communicate our intent to comply with the terms of the Proposed Safety Order and to provide details regarding our plans for compliance. In accordance with the options described in the Proposed Safety Order regarding "Response to the Notice", we intend to comply with the requirements of the Proposed Safety Order and request the opportunity to engage in informal consultation with the hopes of entering into a written consent agreement that addresses the issues raised in the Proposed Safety Order.

Condition 1 of the Proposed Safety Order requires NGT&S to maintain a pressure reduction of 20% of the operating pressure in place at the time of the incident. After completing several maintenance activities, including the replacement of approximately 1,750 feet of pipe at locations similar to the rupture site, NGT&S returned Line P to restricted service. Line P was returned to service at a maximum pressure of 227 psig, which corresponds to a 20% reduction from the operating pressure at the time of the incident. NGT&S will maintain this pressure reduction until the replacement of the remaining bare pipe along Line P is complete.

Condition 2 of the Proposed Safety Order requires the completion of a root cause analysis to determine the cause of the failure and to assess the adequacy of control center processes as they related to the Line P incident. Attachment 1 provides a copy of the root cause analysis. The root cause analysis finds that external corrosion was the primary cause of the incident. The external corrosion occurred due to bare steel in contact with a corrosive environment without the ability to supply cathodic protection (due to the presence of unbonded couplings). While control center processes and SCADA system capabilities were not the primary cause of the incident, several areas for improvement were identified in these areas.

Condition 3 of the Proposed Safety Order requires the development of a work plan to replace all bare, coupled, cathodically unprotected line pipe along Line P within 12 months. Attachment 2 provides a copy of the work plan. NGT&S has already placed an order for the replacement pipe and is planning to begin clearing the right of way in mid November of 2010.

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Response to Notice of Proposed Safety Order, CPF 2-2010-1010S

Conditions 4 through 10 of the Proposed Safety Order specify various procedural requirements, including the providing of monthly progress reports. NGT&S will fully comply with these requirements.

If you have any questions regarding our commitment to comply with the Proposed Safety Order, please do not hesitate to contact me.

Sincerely,

A handwritten signature in black ink, reading "Chad Zamarin". The signature is fluid and cursive, with the first name "Chad" and last name "Zamarin" clearly distinguishable.

Chad Zamarin
Director – Integrity Management
NiSource Gas Transmission & Storage

Attachment 1

Root Cause Analysis

**Line P Rupture
Lawrence County, Kentucky**

Root Cause Investigation

Investigation Team:

Steve Bellini – Engineer, Pipeline Engineering
David Blake – Assistant Chief Controller, Gas Control
Richard Cole – Manager, Field Engineering
Jeffery Hill – Team Leader, Operations
Gregory Lago – Engineer, System Integrity

October 2010

Conclusions and Recommendations

On September 9, 2010 at approximately 5:40 am a rupture occurred along Columbia Gas Transmission's Line P. An internal team completed a root cause investigation covering the cause, detection and response to the rupture. This investigation was conducted in October, 2010. The following is a brief summary of conclusions and recommendations resulting from the investigation.

Conclusions

- A dedicated metallurgical failure analysis is being completed on the ruptured joint. However, based upon the preliminary field evaluation, the primary root cause for the rupture was determined to be due to external corrosion of the pipeline.
- The following key factors have been identified as contributing to the advancement of external corrosion at the failure origin:
 - The presence of a corrosive environment
 - The presence of uncoated steel pipe
 - The lack of cathodic protection due to the presence of un-bonded Dresser couplings that electrically isolate each joint of pipe
- The day prior to the rupture, the valve segment immediately downstream of the rupture site had been isolated and blown down in order to tie in a new 200 foot section of replacement pipe. The pipe was returned to service late that evening. The rupture occurred early the next day.
- During the course of five or six hours during the early morning of September 9, 2010, operations personnel experienced difficulty starting horsepower at Kenova Compressor Station, resulting in increasing pressures along Line P. Although MAOP of the pipeline was not exceeded, increasing pressures at higher than normal levels were experienced along the P-System leading up to the time of the rupture.
- After the rupture, several low pressure alerts and alarms were triggered during the course of the morning of September 9, 2010, which, if recognized as a potential rupture, could have alerted personnel to a potential situation earlier.
- Primary notification of the incident was received via a voicemail message from a landowner, resulting in delayed awareness of the rupture. However, once Operations and Gas Control personnel were aware of the incident, response was within expected timeframes.

Recommendations

- The Company has replaced short sections of bare coupled pipe along Line P where conditions similar to the rupture location were noted.

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- Until replacement of the remaining bare pipe can be made, the pipeline segment between Chestnut Junction and the Kenova Compressor Station will operate at a restricted pressure of 80% of the pressure at the time of the incident, which corresponds to a restricted pressure of 227 psig.
 - The remaining 10.3 miles of bare, coupled pipe along Line P shall be replaced prior to October 31, 2011.
 - Public Awareness communications for the Line P system shall be reviewed to ensure landowners are sufficiently aware of the proper protocol in case of emergency. Literature containing the company's emergency response phone number should be re-distributed and discussed with landowners.
 - Operations shall evaluate the startup process at Kenova and implement measures to ensure that units are started in a manner that prevents unplanned pressure deviations along Line P.
 - A plan shall be developed for returning coupled pipelines to service following an outage. At a minimum, the plan will consider the following:
 - Horsepower requirements / compressor station considerations
 - Resources and personnel necessary for safe and effective restoration
 - Time/duration and pressures necessary for restoration
 - Monitoring requirements during pressure restoration
 - History of the pipeline system
 - Complexity of the system
 - Market conditions
 - An assessment shall be conducted of the feasibility for implementing SCADA rate-of-change alarms as part of the new SCADA system being implemented. These alarms may be useful in recognizing pressure drops due to a rupture or sudden gas loss.
 - More detailed shift turnover procedures should be implemented within the Control Room Management Plan to help ensure that turnover is better tracked and that relevant information is being exchanged.
 - The findings of this Root Cause Investigation should be provided as a "lessons learned" for Gas Controllers to help them recognize similar conditions and consider how they might react differently if faced with similar circumstances.

Incident Overview

On September 9, 2010, at approximately 5:40 am EST a pipeline rupture occurred on Line P. The Line P system originates at Beaver Creek Junction in Floyd County, Kentucky and terminates at the Kenova Compressor Station in Wayne County, West Virginia. The rupture occurred about halfway between Beaver Creek Junction and Kenova Compressor Station, approximately 850 feet south of State Route 645 in Lawrence County, Kentucky. The rupture occurred in a remote, Class 1 area and there were no injuries and no gas ignition. A map showing the Line P System is provided as Appendix A.

The day before the rupture, September 8, 2010, the valve segment immediately downstream of the rupture site had been isolated and blown down in order to tie in a new 200 foot section of replacement pipe. The pipe was returned to service late on the evening of the 8th. The rupture occurred early the following day.

During the course of the evening of September 8, 2010, after the pipeline was brought back in service, operations personnel at the Kenova Compressor Station experienced unexpected problems bringing horsepower online. Normally this station would pull the necessary gas out of the P-System to keep operations balanced. The problems bringing the horsepower online resulted in increasing pressures along Line P, up until the time of the rupture. However, indications from SCADA points measuring close to the rupture site indicate that the MOAP on the Line P was not exceeded.

The company was first made aware of the rupture by a phone call to the Operations personnel from a neighboring landowner. SCADA information along the P-System indicated increasing pressures along Line P leading up to the apparent time of the rupture. SCADA showed decreasing pressure indications that should have led to the recognition of a potential rupture. This would not have prevented the rupture, but it could have reduced the response time and/or the amount of gas that was released.

As noted above, company personnel were first made aware of the rupture by a property owner who left a voicemail message on the office phone of operations personnel. The voicemail message was left approximately one and a half hours after pressure readings now show that the rupture had taken place. Upon arrival at the office approximately 35 minutes later, the voicemail message was retrieved by Operations personnel. Within 20 minutes of receiving the voicemail message, Operations personnel had arrived at the scene and confirmed the rupture. Incident response was then initiated. Operations personnel traveled to the nearest upstream and downstream locations to close the valves to shut off the flow of natural gas to the area. Gas Control was first made aware of the rupture when contacted by an Operations Manager who had interacted with responding Operations personnel upon their arrival at the downstream valve location. Gas Control was not contacted before that time due to the lack of cell service at the rupture site. Mainline valves were shut within one hour of arriving at the scene of the rupture.

In the area of the rupture, Line P operates at an MAOP of 288 psig and flows gas from South to North. The pipe at the point of the rupture is 20 inch outside diameter, uncoated, coupled pipe. The pipe was not cathodically protected. Based upon a preliminary field investigation, the cause

of the rupture has been determined to be due to external corrosion. A laboratory failure analysis is being completed on the rupture joint.

Incident Description

Pipeline System Overview

Line P is a pipeline system that is approximately 66.5 miles long. The system originates at the Beaver Creek Junction in Floyd County, Kentucky and terminates at the Kenova Compressor Station in Wayne County, West Virginia. Gas flows through Line P from South to North, with the southernmost gas supply provided by connections at Beaver Creek Junction with Columbia Gas Lines PM-30 and PM-83. The pipeline carries mainly production gas.

Upstream Segment

Line P consists of two distinct operating segments. The upstream segment originates in Floyd County, Kentucky, at the Beaver Creek Junction with Lines PM-30 and PM-83 and terminates at Chestnut Junction, which is located approximately 28.5 miles from the beginning of Line P. The upstream segment consists of approximately 4 miles of 16" OD and 24.5 miles of 20" OD, coated pipe, installed at various dates between 1948 and 2004. The upstream segment operates at a "grandfathered" MAOP of 360 psig.

Downstream Segment

The downstream segment, which is approximately 38 miles long, originates at Chestnut Junction and terminates at the Kenova Compressor Station. Chestnut Junction is an intersection point where Columbia Gas Line PM-117 intersects to deliver gas into Line P. There is one compressor station, Walbridge, located approximately 15 miles downstream of Chestnut Junction and 23 miles upstream of Kenova; however, the Walbridge Station does not operate as a booster unit along Line P. Walbridge contains a single 800 hp unit that serves to compress local production volumes from Line BM-19, which has an MAOP of 125 psig, into Line P.

The downstream segment consists of approximately 2 miles of 16" OD, 32.5 miles of 20" OD, and 3.5 miles of 24" OD pipe. Approximately 10 miles of the 20" OD pipe is uncoated, coupled and cathodically unprotected, and was originally installed in 1928. The 10 miles of uncoated pipe is located within an area that extends downstream approximately 12 miles from Chestnut Junction. The remaining 28 miles is coated pipe that was installed at dates ranging from 1958 to 1999. The downstream segment had operated at an MAOP of 288 psig prior to the rupture. Since the source of pressure on the downstream segment was the higher pressure provided by the segment upstream of Chestnut Junction, the MAOP of the line was controlled by the pressure protection at Chestnut Junction.

The rupture occurred within the downstream segment of Line P between the Chestnut and Peach Orchard valve settings, in a section of uncoated, coupled 20 inch outside diameter, 0.250 inch wall pipe of unknown grade. The pipe was installed in 1928.

Production gas can enter Line P from PM-30 and PM-83 near Beaver Creek. Gas can also enter through PM-117 at Chestnut Junction, through BM19 at Walbridge and at other receipt points along pipeline. Natural gas flows north through Line P to Kenova Compressor Station, which is located in Wayne County, West Virginia.

Events Prior to the Rupture

As part of 2010 maintenance, approximately 200 feet of uncoated, coupled pipe was replaced just north of the Peach Orchard Valve. The construction project was initiated on August 23, 2010. The new pipe was constructed and offset in order to minimize the outage of Line P. On September 8, 2010, at approximately 6:10 am, the valve segment north of the Peach Orchard valve was isolated and blown down in order to tie-in the new pipe. The pipeline south of the Peach Orchard valve setting, in the area of the rupture, was not taken out of service during this time. The tie-in was completed the same day and in order to reduce customer outages, Operations purged the pipeline that same evening to return it to service. Purging operations began around 8:30 pm and followed a written site specific purge plan (See Appendix B). Operations contacted Gas Control to inform them of the actions being taken and an operator was standing by at Kenova Compressor Station. The pipeline was returned to service at approximately 10:30 pm on September 8, 2010, at which time the Gas Controller contacted major producers (EQT and Chesapeake Energy) in the area to notify them that gas could again flow into Line P.

By approximately 11:00 pm, flows had started coming back into Line P from EQT's Dwale and Chesapeake's Warco measuring stations. In addition, by midnight on September 8, 2010, significant flows were coming into Line P from EQT's Beaver Creek location. As pressures increased, there was a need to run additional horsepower at Kenova Compressor Station. Normally, Kenova Compressor station will pull the necessary gas out of Line P to keep operations balanced. Problems were encountered starting several units at Kenova during the early hours of September 9, 2010.

There are nine compressor units at Kenova Compressor Station. Five of the units operate on the low pressure side and compress gas from production, including the gas from Line P to an intermediate pressure before it flows to a neighboring Mark West plant for processing. Natural gas returned from the Mark West plant enters other pipeline systems for transportation to market or is compressed further through the high side compressor units (Compressor units 5 through 8) before leaving Kenova station.

During the course of five or six hours during the early morning of September 9, 2010, the Operator at Kenova Compressor station experienced difficulty getting horsepower online, which resulted in increasing pressures along Line P. When the flow began increasing along Line P, the Operator attempted to start one of the units and it failed to start. The Operator rolled the crankshaft over and tried several more times before it finally started. Due to the units being in auto speed and auto torque the units sped up for maximum throughput and the pressure began to drop on the suction header. The suction controller began reacting to compensate but was not quick enough to keep the units from going down on low suction. Over the next hour or so, the operator was successful in getting the low stage units back online. MarkWest then began putting their plant back on line and in doing so they tripped open their bypass, which put the high side

units in overload causing all three units to shutdown. This also caused the bypass on the low side units to open up. The operator then restarted the high side and finally was able to get things into a normal mode. Charts showing the status of each of the nine units during the twelve hour time period from 10:00 pm on 9/8/2010 to 10:00 am on 9/9/2010 are shown in Appendix C. Since the time of the rupture, the Kenova Team has evaluated the startup process. In the future, in similar circumstances, the low side units will be started in manual mode so they can be brought on slowly to avoid low suction shutdown. In addition, dependent upon the circumstances, additional personnel will be called out to assist with the startup process.

Gas Control and System Monitoring

Gas Control uses the Supervisory Control and Data Acquisition (SCADA) system to monitor pipeline system pressures and flows, to control regulation and to turn compressor units on and off along the company's pipeline system. High pressure level SCADA alarms are set in the SCADA system at the MAOP of the pipeline system being monitored (high-high SCADA levels). In addition, in some cases low pressure level alarms may be set (low-low SCADA levels) at contract or other critical pressures. Only Gas Control Chiefs or Assistant Chiefs have the authority to set high pressure (high-high level) alarms in the SCADA system. However, alert levels (below the MAOP) can be set up by individual controllers to alert them to changes in the pipeline conditions as an aid in monitoring the pipeline system. These alert levels can be continually adjusted to alert the controller to changes in operating conditions. For instance, for a pipeline with an MAOP of 1,000 psig, the high-high level alarm would be set by a Chief or Assistant Chief at 1,000 psig in SCADA. However, for monitoring purposes, the individual Gas Controller might set high and low SCADA alert levels at 950 psig and 850 psig respectively, so that the system would alert the controller when the pipeline pressure either exceeded 950 psig or went below 850 psig.

There are several SCADA points along the Line P system. However, none of the points are located in the immediate vicinity of the pipeline rupture. The SCADA telemetry point closest to the rupture site is located approximately 10 miles downstream. In reviewing the historical information, SCADA was functioning properly and none of the existing data points from the area had been inhibited during the period before or following the rupture.

The table below shows the alarms and alerts on or around Line P that were received and acknowledged by the gas controllers during the course of the evening of September 8, 2010, and the morning of September 9, 2010. A review of the data indicates the following:

- Except for the high-high pressure alarms which occurred on the intermediate compression stage at Kenova (which may be related to but is not necessarily directly reflective of the pressures on the P-System), no high-high pressure alarms appear to have been triggered on the P-System and the pipeline pressures at the individual SCADA points did not exceed MAOP.
- Several low pressure alerts and alarms were triggered during the course of the morning of September 9, 2010, which, if recognized as a potential rupture, could have alerted personnel to a potential situation earlier.

SELECTED KEY ALARM AND ALERT EVENTS 9/8/10-9/9/10

LOCATION	DATE	TIME	EVENT AND DESCRIPTION
UPSTREAM OF RUPTURE SITE			
BEAVER CREEK	9/9/10	5:36 AM	LINE P HIGH ALERT (330.1 #s)
		5:37 AM	ACKNOWLEDGEMENT
		6:27 AM	LINE P LOW ALERT (299.8 #s)
		6:37 AM	ACKNOWLEDGEMENT
		7:18 AM	LINE P LOW ALERT (279.5 #s)
		7:32 AM	ACKNOWLEDGEMENT
TOMAHAWK	9/8/10	10:57 PM	TOMAHAWK STATIC PRESSURE ALERT (300.1 #s)
		11:02 PM	ACKNOWLEDGEMENT
DOWNSTREAM OF RUPTURE SITE			
WALBRIDGE	9/9/10	2:17 AM	LINE B HIGH PRESSURE (241.2 #s)
		2:17 AM	ACKNOWLEDGEMENT
		2:32 AM	ENGINE 1 OFF LINE
		2:33 AM	ACKNOWLEDGEMENT
		5:51 AM	LINE B LOW PRESSURE (200.9 #s)
		5:52 AM	ACKNOWLEDGEMENT
		6:48 AM	LINE B LOW PRESSURE (107.6 #s)
		6:48 AM	CONTROLLER #2 ENTERED 90# LOW FOR LINE B ALARM
		7:03 AM	LINE B LOW PRESSURE (87.0 #s)
		7:06 AM	ACKNOWLEDGEMENT
KENOVA	9/9/10	7:44 AM	LINE B LOW PRESSURE (68.6 #s)
		7:44 AM	CONTROLLER #2 ENTERED 55# LOW FOR LINE B ALARM
		5:32 AM	LINE B INTERMEDIATE CMP STAGE - HIGH PRESSURE ALERT (353.8 #s)
		5:32 AM	ACKNOWLEDGEMENT
		5:50 AM	LINE B INTERMEDIATE CMP STAGE - HIGH-HIGH PRESSURE ALARM (360.9 #s)
		5:51 AM	ACKNOWLEDGEMENT
		5:53 AM	LINE B INTERMEDIATE CMP STAGE - HIGH-HIGH PRESSURE ALARM CLEAR (359.9 #s)
		5:56 AM	LINE B INTERMEDIATE CMP STAGE - HIGH-HIGH PRESSURE ALARM (360.5 #s)
		6:05 AM	LINE B INTERMEDIATE CMP STAGE - HIGH-HIGH PRESSURE ALARM CLEAR (355.6 #s)
		6:17 AM	ACKNOWLEDGEMENT
		7:03 AM	LINE P LOW PRESSURE ALERT (88.9 #s)
		7:07 AM	ACKNOWLEDGEMENT
		7:09 AM	LINE P LOW PRESSURE ALERT AND LOW-LOW PRESSURE ALARM (84.0 #s)
		7:10 AM	ACKNOWLEDGEMENT

The estimated time of the event from SCADA information appears to be around 5:40 am EST on September 9, 2010. Gas Control Shift change reportedly occurred around 5:50 am. The change of information at shift change included clarifying the Line P project had been completed the previous night and that production rates had increased. In addition, there was a discussion concerning the problems that Kenova Compressor Station had experienced in getting the desired amount of horsepower online. There was a low pressure alert on line B at Walbridge at 5:51 am.

There were a variety of factors that could have had a negative influence on the gas controller's ability to quickly recognize the event. In the hours leading up to the event, there were changing conditions throughout the P-System that added complexity to the situation. Line P had been put in service, production rates had increased, and mainline horsepower downstream of the rupture area had experienced problems and had been intermittently running and stopping. In addition, as shift change had just occurred, the fresh controller may have not been fully aware of all of these

changing conditions and pressure trends throughout the evening. All of this activity may have hampered the clarity of the gas controller's ability to detect the leak.

The incoming day shift Gas Controllers were observed to be performing duties in a manner that displayed no signs of fatigue. Per company procedures, the day shift controller on duty when the incident was discovered was sent that morning for drug and alcohol testing. The results of the tests were negative.

The table below shows the sequence of significant events along Line P from the evening of September 8, 2010, through 7:00 am on September 9, 2010.

SEQUENCE OF SIGNIFICANT EVENTS

9/8/10-9/9/10

9/8/10	6:51 PM	KENOVA C/S ON-CALL IS CONTACTED ABOUT UNIT #7 FAULTING WHILE RUNNING. THE CONTACT PERSON RESPONDS AND TRAVELS TO THE STATION.
	9:49 PM	FIELD PERSONNEL CONTACT GAS CONTROL AND LET THEM KNOW THAT THEY ARE FINISHING UP A LINE JOB ON LINE P AND WILL BE PURGING IT AND BRINGIN IT BACK TO SERVICE BRINGING IT BACK IN SERVICE
	9:55 PM	FIELD PERSONNEL PURGING AND LOADING SEGMENT OF LINE P IN THE PEACH ORCHARD AREA
	10:30 PM	LINE PURGING COMPLETED. GAS CONTROLLER #1 CONTACTED CHESAPEAKE ENERGY AND EQT TO ALLOW THEM TO BEGIN FLOW AT SOME OF THEIR PRODUCTION METERS.
9/9/10	10:46 PM	PRESSURES ON THE P-SYSTEM HAVE STARTED BUILDING STEADILY INDICATING LINE IS BACK IN SERVICE
	11:00 PM	FIELD OPERATIONS DEPART THE SITE. FLOWS HAVE STARTED AT DWALE (EQT) AND WARCO (CPK) RECEIPT METERS
	12:00 AM	SIGNIFICANT FLOW HAS STARTED AT BEAVER CREEK (EQT)
	12:51 AM	NYE UNIT #1 TRIPPED OFF LINE
	1:00 AM	PRESSURES STEADILY BUILDING THROUGHOUT THE P-SYSTEM
	1:41 AM	HUBBALL UNIT #2 TRIPPED OFF LINE
	2:00 AM	PRESSURES STEADILY BUILDING THROUGHOUT THE P-SYSTEM
	2:32 AM	WALBRIDGE -ENGINE 1 OFF DUE TO HIGH PRESSURE RELATED TO KENOVA ISSUES
	3:00 AM	PRESSURES STEADILY BUILDING THROUGHOUT THE P-SYSTEM
	4:00 AM	PRESSURES STEADILY BUILDING THROUGHOUT THE P-SYSTEM
	5:00 AM	PACE OF BUILDING PRESSURES ON P-SYSTEM HAS SLOWED
	5:38 AM	TOMAHAWK M/S PRESSURE PEAKS AT 289.8 #/S
	5:40 AM	APPROXIMATE TIME OF LINE P PIPELINE RUPTURE
	5:50 AM	GAS CONTROL SHIFT CHANGE
	6:00 AM	PRESSURE HAS ALREADY DROPPED QUICKLY IN THE WALBRIDGE AREA
	7:00 AM	SIGNIFICANT DROPS IN PRESSURE CAN BE SEEN AT WALBRIDGE, DWALE, BEAVER CREEK, AND KENOVA AT THIS POINT

Note: Gas Controller #1 refers to the nightshift controller while Gas Controller #2 refers to the dayshift controller.

Notification of Event and Response Actions

As noted above, based upon the SCADA data, it appears that the actual time of the rupture along Line P was approximately 5:40 am on September 9, 2010. Company personnel were first notified of a potential event via a voicemail message left on the Inez office phone of a Company Pipeliner by a neighboring property owner. The response events are set out in the following table.

Time	Description
7:05 am	A property owner (Mr. Fitch) leaves a voicemail for Carl "Doug" Napier (Pipeliner) with regard to a possible event on Line P.
7:39 am	Mr. Napier arrives at his office and receives the voicemail message regarding the rupture.
7:49 am	After speaking to Danny Weddington (Team Leader, Maintenance) and James Lance (Pipeliner A) about pressures on Line P, Mr. Napier leaves the office to go to the site.
8:00 am	Mr. Napier arrives at the mouth of the hollow where the rupture had occurred. He gets out of his vehicle and briefly speaks with a volunteer fireman (in his personal vehicle) and another unidentified person. He explains that he is from the gas company and is investigating the event. Darrel Tackett (Pipeliner) arrives on site. Mr. Napier and Mr. Tackett walk a short distance and discover that the pipe has ruptured. There was no cell phone service at this site.
8:15 am	Mr. Tackett leaves for the Chestnut mainline valve (the nearest upstream valve) and Mr. Napier leaves to go to the Peach Orchard mainline valve (the nearest downstream valve).
8:35 am	Mr. Napier arrives at the Peach Orchard mainline valve. He calls Ralph Hall (Manager, Operations) and informs him of the rupture and that he is closing the Peach Orchard mainline valve. Mr. Napier closes the valve. Mr. Hall contacts Gas Control (Jim Cooper) to confirm the rupture.
8:36 am	The Gas Control Monitoring Center Initiates the Monitoring Center Notification Log
8:46 am	The Monitoring Center contacts NGT&S Senior Management and customers Chesapeake and Equitable to have them shut in production.
8:49 am	The Monitoring Center contacts Michael Elkins (Engineer - System Integrity) regarding the rupture.
8:50 am	Mr. Tackett closes the PM-117 valve located at Chestnut Junction.
9:00 am	Mr. Tackett closes the Line P mainline valve at Chestnut Junction.
9:16 am	The Monitoring Center Initiates an Incident Management Plan meeting – set for 11:00 a.m. and proceeds with contacting appropriate company personnel.
9:20 am	Jason Castle (Dist. Instrument Mechanic B) turns off measuring station #840402
9:25 am	Mr. Castle turns off measuring station #838432
9:30 am	Mr. Castle turns off measuring station #836982
9:30 am	Mr. Napier visits the rupture site and reports to Ralph Hall that a section of pipe is blown out between two couplings.
9:35 am	Mr. Elkins and George Hamaty (Engineer – System Integrity) contact the National Response Center to report the incident (NRC Report#953483, Officer Kevin Williams).
10:20 am	Mr. Castle turns off measuring station #808424
11:00 am	Incident Management Call commences.

On-site response to the rupture followed the Company Emergency Plan. It should be noted that Gas Control does not have the ability to isolate this section of pipeline remotely.

Investigation:***The Pipeline***

Immediately after responding to the rupture, Operations secured the site scene. Shortly thereafter, company Operations and Engineering Services staff began collected on site data regarding the incident. Photos, measurements field tests were made and collected. The next day the ruptured joint along with short sections of the adjacent joints were covered with plastic and carefully loaded onto a flatbed truck for transport to a nearby field office garage for security and preservation until the material could be transported to DNV for metallurgical analysis. The joints were transported to DNV in Columbus Ohio a few days later.

Site Evaluation

The failure occurred in a dry creek bed in an area of rough terrain with steep banks on either side of the creek. The rupture area and area south of State Route 645 is a wooded and remote area with no nearby structures. A picture of the rupture site is provided in Figure 1.

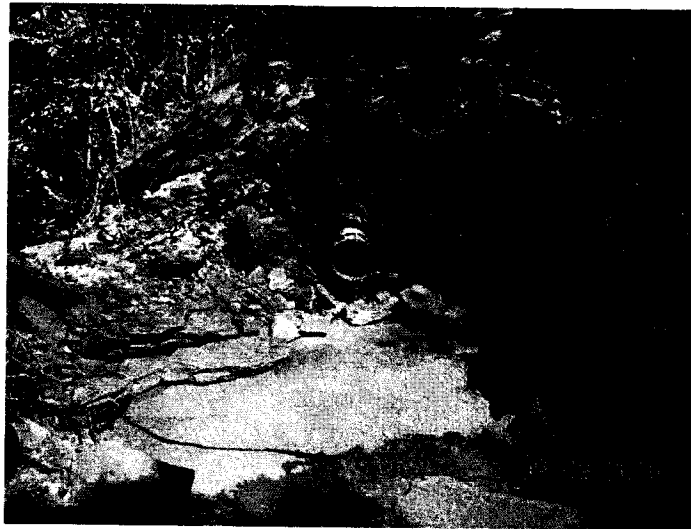


Figure 1. Picture of the rupture site, showing a remaining coupling on the downstream pipe end.

An assessment of the site indicated that the failure occurred in a section of uncoated pipe that was constructed in the late 1920's with Dresser couplings as the joining method between 20 foot nominal lengths of pipe. An approximately 20 foot long joint of pipe was expelled from the failure site, landing approximately 90 feet from the rupture site. The expelled piece was a full 20 foot joint of pipe, expelled from the nearest upstream and downstream coupling connections. The origin of the failure appeared to be within the expelled joint, located approximately 7 to 8 feet from one end of the joint. A preliminary evaluation of the failure origin indicated an area of reduced wall thickness on the external surface, likely caused by external corrosion. Wall thickness measurements of 119 – 120 mils were recorded using a UT gauge at the likely origin, as compared to a measurement of 301 mils near the end of the joint. A visual examination of the internal surface of the expelled pipe indicated no presence of internal corrosion. Pictures from the site investigation are provided in Figure 2.



Figure 2. A photo of the expelled joint and a close up of wall thinning on the external surface of the likely origin

The pipe remaining at the north end of the rupture site had approximately 48 to 60 inches of cover (to top of pipe). The pipe remaining at the south end of the rupture site had depth of cover ranging from 24 to 36 inches to the top of pipe, with cover measurements increasing moving away from the rupture site. The pipe remaining in the south end of the rupture site appeared to have moved slightly as a result of the force of the rupture. No such evidence was noted on the pipe remaining at the north end of the rupture site.

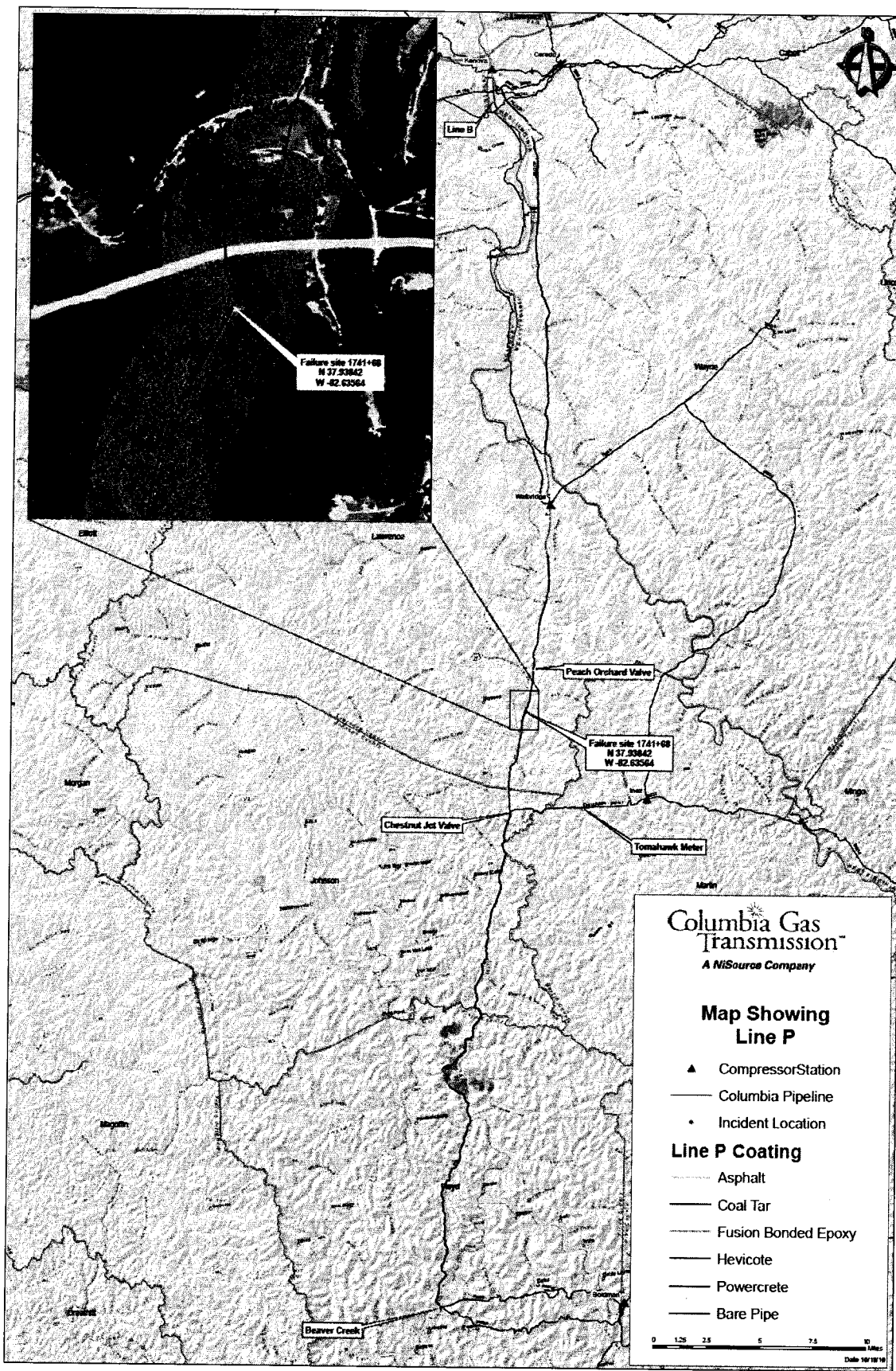
One coupling was attached to the pipe remaining in the south end of the rupture site and one coupling remained with the pipe at the north end of the rupture site. No damage was noted on either coupling and visual examination of the internal surfaces inside the open ends on both sides of the rupture indicated no presence of internal corrosion. The pipe remaining in the north end of the rupture site sloped downward at an angle of approximately 15 -20 degrees (estimated by eye). The pipe remaining in the south end of the rupture site did not appear to be sloped any more than five degrees (estimated by eye).

The pH near the pipe remaining at the north and south ends of the rupture site was measured to be around 4 using an antimony probe and voltmeter. Soil resistivity was measured to be 20,107.5 ohm-cm, using the Weiner four pin method, at a location perpendicular to the pipe remaining in the south end of the rupture site. Soil in the area appeared to be clay with underlying rock. There were no overhead electric transmission lines or other foreign utilities in the area of the rupture.

The Line P pressure at the time of the event was determined to be 284 psig at the failure location. This is based upon a pressure of 290 psig, recorded at the Tomahawk Measuring Station, which is located on PM-117, between the Inez Compressor Station and the connection with Line P at Chestnut Junction. Tomahawk Measuring Station is approximately 8 miles from the rupture site and the MAOP of Line PM-117 is 295 psig. The elevation at the rupture site is 590 feet, the elevation at Chestnut Junction is 960 feet and the elevation at Tomahawk Measuring Station is 680 feet.

Appendix A

Line P System Map



Appendix B

Kenova Site Specific Purge Plan for Line P



**NiSource Gas
Transmission & StorageSM**

Columbia Gas Transmission

**Blow Down and Purge Procedure's
Line P-20"
VS-7088**

**Inez Operations
Lawrence County, Kentucky
Peach Orchard VS to Walbridge VS**

**Inventory Station 1859+95 to 2280+65
42,720 Feet in Length (8.09 Miles)**

**Peach Orchard Relocation
Project 12736**

Prepared by:

James Bowling
Technical Specialist - EMS

Date:

September 4, 2010

♦ **Reason for Blow Down:**

This plan was prepared to safely remove Line P from service to allow the tie-ins to be completed on a relocation project. The blow down segment begins at the Peach Orchard Valve Setting (1859+95) and ends at the Walbridge Valve Setting (2280+65). It is anticipated that the pipeline will be out of service for 1 day.

♦ **Columbia Gas Transmission Personnel participating in the blow down/purge:**

1. **Jeff Hill**, Team Leader, or his designee will act as the Blow Down Coordinator and be in charge of all activities during the blow down and purge procedures.
2. Mainline Valve Settings will be operated by **Operations Personnel** as assigned.

Operations Personnel

<u>Employee</u>	<u>Title</u>	<u>Cell</u>	<u>Office</u>	<u>Unit</u>	<u>Pager</u>
Ralph Hall	Asset Manager	859-556-2363	859-745-6403	35	859-527-2033
Jeff Hill	Team Leader	304-784-0901	606-478-6303	325	304-540-3467
James Lance	Roustabout A	606-791-7360	606-478-6311	2013	606-482-9704
Carl Gross	HEO	606-477-3487	606-478-6311	48	606-482-9710
Dave Bailey	Welder	606-791-3488	606-478-6311	538	606-482-9708
Cledith Howard	Roustabout B	606-794-7358	606-478-6311	598	606-482-9707
Rick Wells	Roustabout B	606-791-7357	606-478-6311	549	606-482-9715
Mike Rodebaugh	DIM	606-791-9885	606-478-6307	602	606-482-9719
Doug Napier	Roustabout A	304-654-9742	606-298-0807	_____	304-540-1869
Darrell Tackett	Roustabout B	606-794-7361	606-298-0807	_____	none
Paul Roberts	DIM	606-794-9884	606-478-6306	586	none
Steve Bellini	Pipeline Eng'r	304-543-3523	304-722-8657	none	none
Tammy Keathley	Administrative	606-794-5477	606-478-6301	none	none

Contractor Personnel

Bill Kirk 304-373-6126(c): 304-373-6116 (c) LOCK-OUT/TAG-OUT COORDINATOR
Rick Harris 304-941-7356(c)

Inspection Personnel

Rob Thompson Chief Inspector 304-542-2650(c)
? Welding Insp. ?(c)
Terry Shamblin Environmental 304-552-4242(c)
Bess Fleming Corrosion Insp. ?(c)

Construction Management

Terry Johnson 304-380-6774(c) 304-722-8655(o)
James Bowling 859-753-8500(c) 606-739-2226(o)

Pre Blow Down Contact Requirements:

Operations Team Leader or designee will coordinate with Gas Control in Charleston prior to blow down to assure the September 8th date is still acceptable for taking this section of pipeline out of service until the tie-ins are completed.

Each job must be approved through the Outage Calendar prior to commencement of gas evacuation. A copy of this Blow Down and Purge Plan may be requested for review at the discretion of Gas Control. A record of who was contacted, their response and the time of the call shall be documented.

Team Leader or designee to contact all customers, both internal and external, who will be impacted by this outage to inform, plan, and coordinate as necessary so as to assure that all concerns have been addressed prior to execution of this plan. (See list below).

Local Authorities must be notified (24) twenty-four hours in advance of beginning the blow down, requiring notification on September 7th. All contacts will be made at the direction of Local Operations Team Leader, or designee.

♦ **Local Authority Contact Information - Police / Fire / Hospital / Emergency Services:**

Kentucky Natural Resources and Environmental Protection – Office	
Of Air Quality – Ashland Office – Karen Deskins	(606) 929-5285
Gas Control	(304) 357-2505
Monitoring Center	(304) 357-2008
Cherryville Fire Department	(606) 673-3311
Lawrence County Sheriff	(606) 638-4368 -
Director of Emergency Management	(606) 638-0334 -
Kentucky State Police (Ashland Post)	(606) 928-6421 -

Home Owners near the Blow-Down site

***911 should be utilized in an emergency**

Gas Control and the Monitoring Center will be informed throughout the entire project.

♦ **Operational Safety & Environmental Considerations:**

Policy, Plan and Procedure (PP&P) Review

- Lock-out/Tag-out (LOTO) procedures outlined in PP&P 110.01.10 during all valve operations.
- Isolation, Blow Down and Purging of Gas Handling outlined in PP&P 220.04.02
- Prevention of Accidental Ignition procedures outlined in PP&P 220.04.05.
- Hydrogen Sulfide (H₂S) precautions outlined in PP&P 110.01.06 Sections 3.2 & 3.4. (See Attachment A)

Other:

- Evaluate any blow down operation within 300 feet of overhead power lines. **No overhead power lines are affected.**
- At a minimum 20 lb fire extinguishers should be available at each blow down location.
- Provide means to monitor and control blow down and re-pressurization so as to prevent over-pressure of any facility.
- Rectifier must be turned off 48 hours prior to beginning of blow down and/or purge procedures.
- Prior to commencement of blow down and/or purge procedures, check for and mitigate, if necessary, any stray current at all gas evacuation sites.
- Consider strategic placement of spill kits.
- Review OEP-102, Use of Air Movers when Cutting and Welding (See Attachment B)

Pre Blow Down Preparation:

The appropriate Team Leader, or designee must obtain customer, homeowner, and environmental information.

It is recommended that a visit and inspection of each required site on the blow down plan be conducted to help assure familiarity and to confirm initial operating position of the valves at each site. Map corrections should be provided to the Technical Data & Design team for any discrepancies between existing drawings and material at each site.

All valves listed in this plan will be operated, lubricated if necessary and partially operated prior to commencement of blow down plan activities to help assure proper operation.

Report valve problems to the Operations Team Leader or designee prior to blow down or purge.

Inventory Map Numbers:

4200N/356E (w/detail)	Peach Orchard Valve Setting
4204N/356E	MS27566; MS30586
4208N/356E	MS19455
4212N/360E (w/detail)	Walbridge Valve Setting

Bayiden - 2
Map Exploration

Pipeline MAOP:

Maximum Allowable Operating Pressure (System MAOP) has been verified to be ²⁸⁸~~366~~ psig. This MAOP must not be exceeded during re-pressurization.

Pre Blow down and/or Pre Purge Safety Meeting and Final Walk-Through of the Plan:

Note:

Blow down or purge operations may not begin unless this plan has been reviewed and signed by the responsible Team Leader or designee.

Operations Team Leader or Designated Blow Down Coordinator:

Ensure that all personnel performing tasks required under the DOT Operator Qualification Rule are currently qualified under the Columbia Operator Qualification Plan.

Review information from the Operational Safety & Environmental Considerations section above as necessary.

Ensure that all vehicles are located away from blow off vent to prevent possible ignition of blowing gas. Cell phones, pagers, and all other non-intrinsically safe devices, which represent possible sources of ignition, must be turned off or removed from the immediate vicinity of the gas vent.

Final walk-through of the plan should be completed at this time. Ensure all personnel are aware of their roles and responsibilities during the blow down and purge operations.

If at any time there are safety concerns - terminate the blow down or purge until such time that the safety concerns are cleared.

♦ **Sequence of Events for Blow Down:**

1. Make sure "Emergency Officials" have been notified
2. Establish effective and secure communications between all Columbia Gas Transmission personnel participating in the blow-down activities
3. Monitor pressure on south blow-off valve at Walbridge VS
4. Notify Gas Control prior to blow down
5. Begin isolation of system by positioning valves as indicated in the individual valve operations guide
6. Open north blow-off valve at the Peach Orchard VS to begin blow-down procedure.
7. Make note of the start pressure at commencement of blow-down
8. Notify Gas Control when gas evacuation to atmosphere is complete and the blow-down procedure is finished
9. Local Operations personnel will now turn responsibility of the facility over to the appropriate Chief Inspector.

Blow-Down Procedure – Peach Orchard VS to Walbridge VS

Warning: Steps must be taken to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion. When a hazardous amount of gas is being vented into the open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided. Gas or electric welding or cutting may not be performed on the pipeline or pipeline components that contain a combustible mixture of gas and air in the area of work. Post warning signs, where appropriate.

Note 1: Close, Tag and Lock Out per Plan #: 110.01.10 *Lock Out/Tag Out*.

Note 2: Blow Down Procedure and Evacuation per Plan #: 220.04.02 *Isolation, Blow Down and Purging of Gas Handling Facilities and Equipment*

Note 3: Potential exists for the presence of Hydrogen Sulfide (H₂S) in the gas stream. Follow procedures as per Plan # 110.01.06, *Safety Requirements for Operations Involving Hydrogen Sulfide – Sections 3.2 and 3.4. – See Attachment A*

♦ **Location of Gas Evacuation:**

Gas will be evacuated through the northern 4" Blow-Off Valve P-217 (inventory station 1859+95) at the Peach Orchard Valve Setting.

♦ **List All Customers that will be impacted by this outage (POD's, POR's, Farm or Small Consumer Taps):**

- **There are no residential consumer taps located in this valve segment**
- **Hay Exploration – Producer Meter - MS-19455 – Inventory Station 2147+17**
Will be out of service until tie-ins are completed and line purged of air.
- **Hay Exploration – Producer Meter - MS-30586 – Inventory Station 1971+88**
Will be out of service until tie-ins are completed and line purged of air.
- **Badien Gas – Producer Meter - MS-27566 – Inventory Station 1937+83**
Will be out of service until tie-ins are completed and line purged of air.

Review with appropriate M&R personnel to make certain all potential customer issues have been identified and documented here.

♦ **Home Owners / Business' Near Blow Down Site:**

All property owners within site of the proposed blow down will be notified, however, should not be impacted by the operation. There are no businesses that will be affected by the proposed blow down.

♦ **Overhead utility or water body within 300 feet of Blow Down Site:**

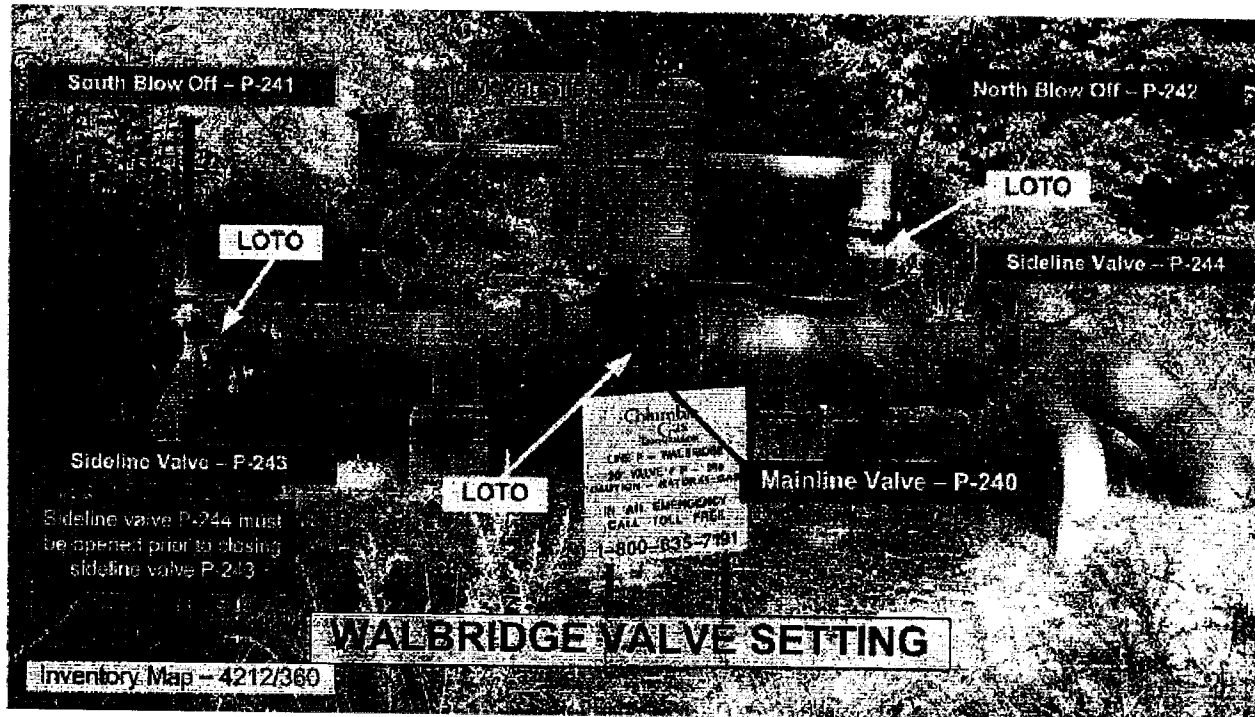
Power Lines – Cable – Telephone: None – Valve setting on ridge above all utilities
Wetland – Pond – River – Lake: None

Individual Valve Operations Guide for Blow Down:

- 1. Hay Exploration – Producer Meter - MS-19455 – Inventory Station 2147+17**
 1. Close, tag and lock-out sideline valve, unnumbered - LOTO
- 2. Hay Exploration – Producer Meter - MS-30586 – Inventory Station 1971+88**
 1. Close, tag and lock-out sideline valve, unnumbered - LOTO
- 3. Badien Gas – Producer Meter – MS-27566 – Inventory Station 1937+83**
 1. Close, tag and lock-out sideline valve, unnumbered – LOTO

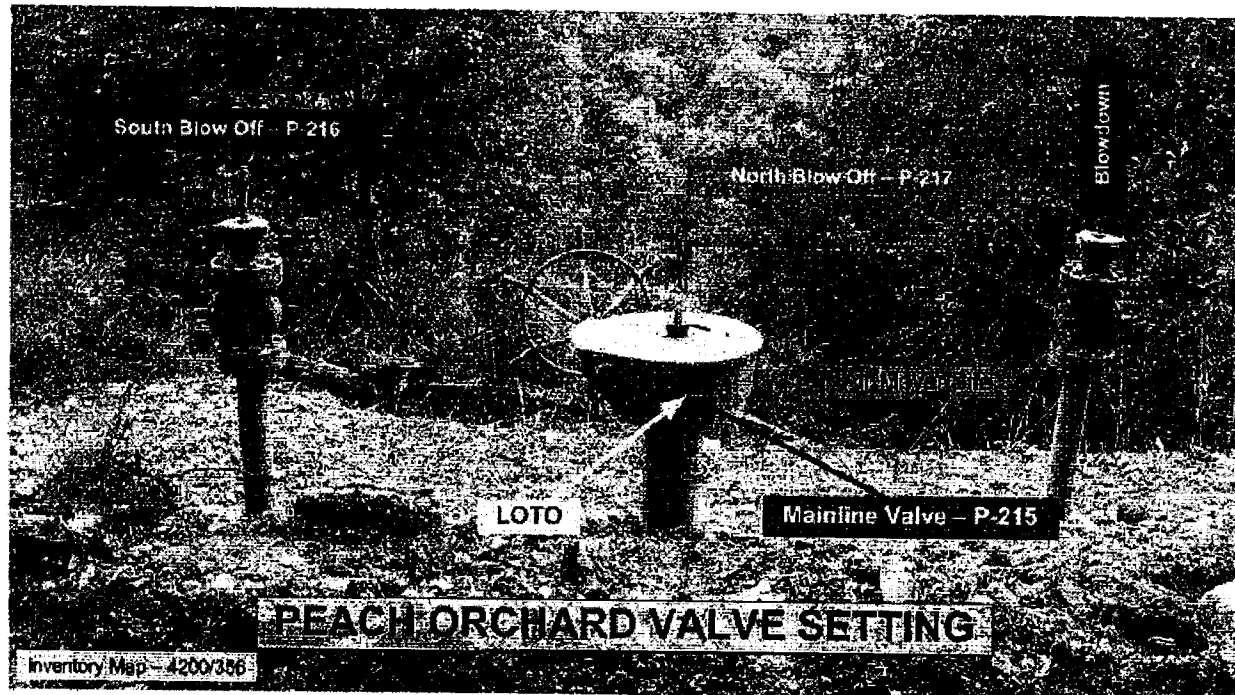
4. Walbridge Valve Setting – Inventory Station 2280+65

1. Close, lock out and tag out mainline valve P-240 – LOTO
2. Open sideline valve P-244 prior to closing sideline valve P-243
3. Close, lock-out and tag-out blow-off valve P-242 – LOTO
4. Close, lock-out and tag-out sideline valve P-243 – LOTO
5. Open blow-off valve P-241



5. Peach Orchard Valve Setting – Inventory Station 1859+95

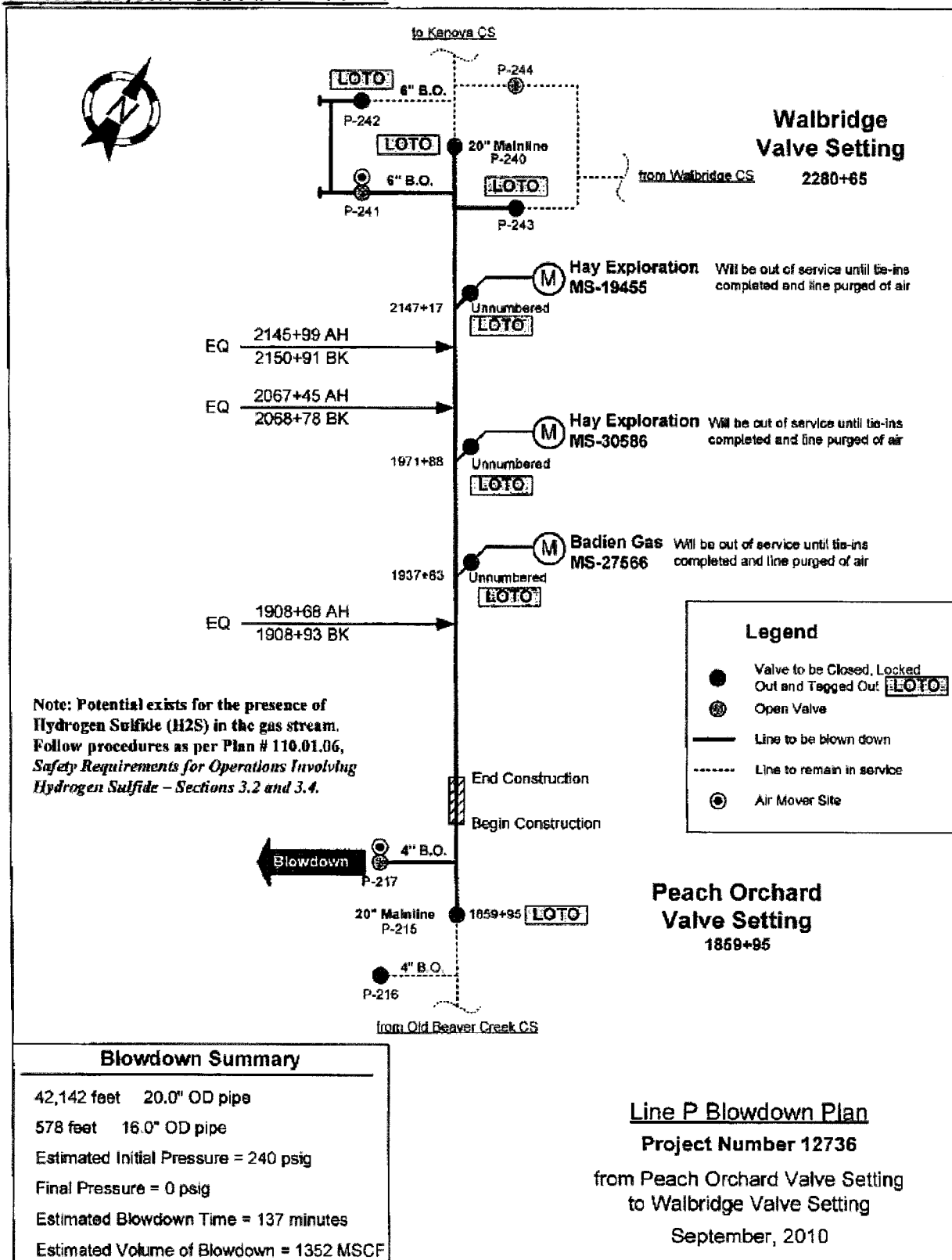
1. Close, lock out and tag out mainline valve P-215 – LOTO
2. Blow-off valve P-216 is to remain closed
3. Blow-off valve P-217 is to be opened to Blow Down Line



♦ Use of Air Movers:

An air mover will be installed at the Peach Orchard Valve Setting and the Walbridge Valve Setting. The air mover will be operated at all locations using compressed air. The necessity of the use of the air mover will be dictated by the activities of the construction crew. Adequate communication must be maintained between the construction crew and the air mover operator. Activation of the air movers will create a suction that will pull gas away from the construction activities.

Sketch of system to be blown down:



Estimated Blow Down Gas Loss Data:

The calculator in Technical Toolbox shall be used to estimate gas loss and duration of the blow down.

This segment of line P is comprised of 42,142 feet of 20.00" OD pipe and 578 feet of 16.00" OD pipe. Based on an estimated line pressure of 240 psig the estimated blow down time is 137 minutes with an estimated gas lost of 1352 MSCF.

Actual gas loss will be calculated after blow down has been completed, then entered in the Maximo system.

Purge Procedure – Walbridge VS to Peach Orchard VS

♦ Sequence of Events for Purge:

(Note that the Purge Plan utilizes the Inlet Control Point Method)

1. Team Leader or the Blow Down Coordinator will establish effective and secure communications between all Columbia Gas Transmission personnel participating in the purging activities.
2. Purging will be from the Walbridge Valve Setting to the Peach Orchard Valve Setting.
3. Establish secure communications between the Inlet Control Point, south blow-off, at the Walbridge Valve Setting and the Peach Orchard Valve Setting, north blow-off.
4. Install Calibrated Low Pressure Gauge at the Walbridge Valve Setting to gauge the line pressure at the Inlet Control Point, south blow-off.
5. Implement Lock-out / Tag-out plan for valve positioning changes.
6. Follow valve positioning instructions as shown on sketch below and initiate purge.
7. Track the elapsed time of approximately **28 minutes** from the commencement of the purging activity or when **36 psig** is reached and maintained for that duration of time at the Inlet Control Point at the Walbridge Valve Setting, south blow-off.
8. Regardless of the timing and / or the ability to hold a given pressure at the Inlet Control Point the gas stream must be checked at the new Peach Orchard Valve Setting, north blow off, with an instrument to assure 100% gas content is obtained.
9. Position valves back to normal operating positions or as directed by Gas Control
10. Notify gas control that purge operations have been completed.

♦ Individual Valve Operations for Purge:

1. Hay Exploration – Producer Meter - MS-19455 – Inventory Station 2147+17

1. Unnumbered sideline valve is to remain closed, locked-out and tagged-out -
LOTO

2. Hay Exploration – Producer Meter - MS-30586 – Inventory Station 1971+88

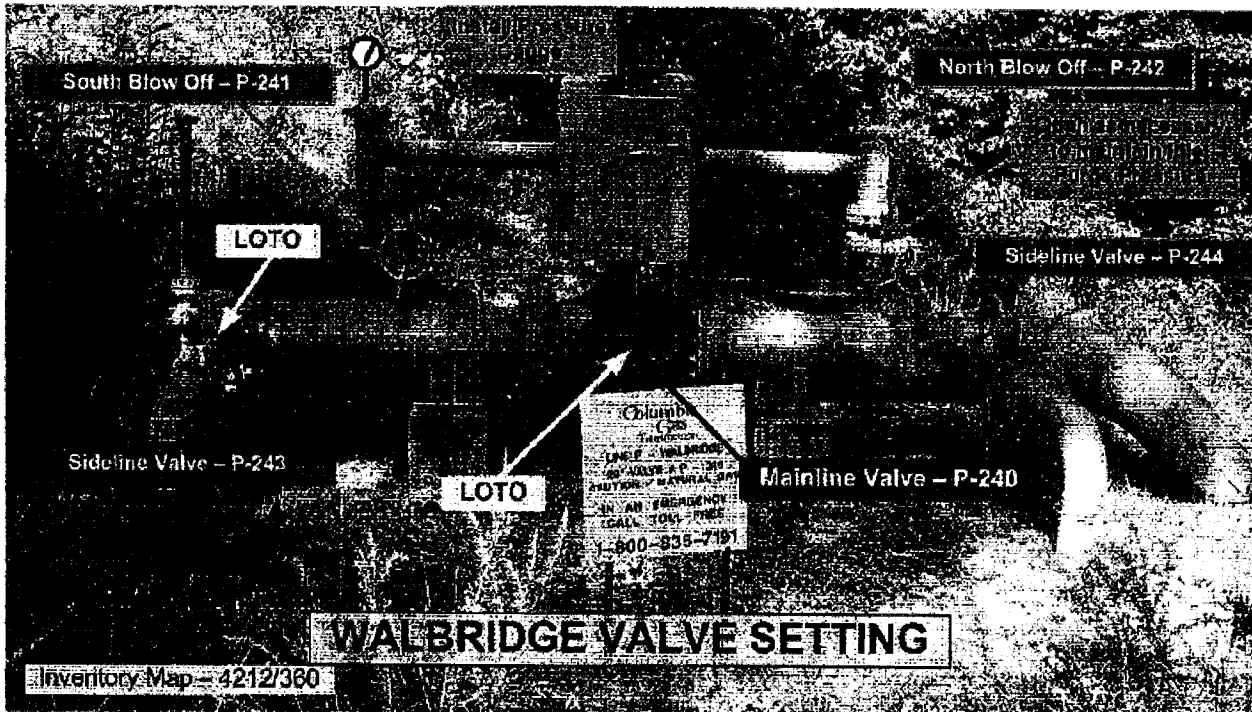
1. Unnumbered sideline valve is to remain closed, locked-out and tagged-out -
LOTO

3. Badien Gas – Producer Meter – MS-27566 – Inventory Station 1937+83

1. Unnumbered sideline valve is to remain closed, locked-out and tagged-out -
LOTO

4. Walbridge Valve Setting – Inventory Station 2280+65

1. Mainline valve P-240 is to remain closed, locked-out and tagged out - LOTO
2. Sideline valve P-243 is to remain closed, locked-out and tagged out – LOTO
3. Sideline valve P-244 is to remain open
4. North blow-off valve P-242 is to be used to regulate the inlet purge gas pressure.
5. South blow-off valve P-241 is open and calibrated pressure gauge installed.

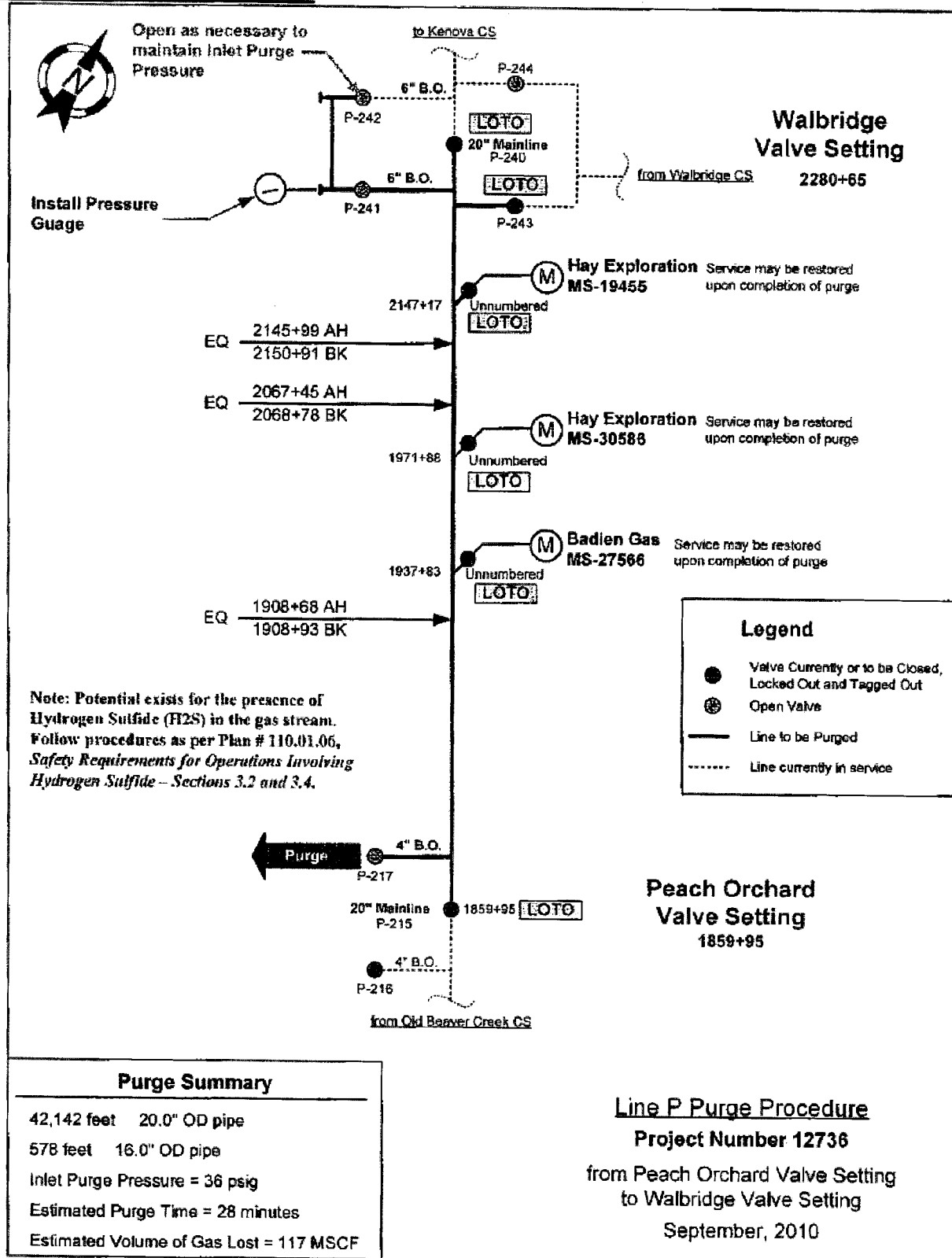


5. Peach Orchard Valve Setting – Inventory Station 1859+95

1. Mainline valve P-215 is to remain closed, locked-out and tagged-out – LOTO
2. South blow-off valve P-216 is to remain closed
3. North blow-off valve P-217 is open – This is the receipt point of the purge gas.



Sketch of system to be Purged:



Estimated Purge Gas Loss Data:

The purge time is calculated at 28 minutes with an inlet purge pressure of 36 psig. The estimated amount of gas lost during the purge is 117 MSCF. The total length of 20.00" OD pipe and 16.00" OD pipe to be purged on line P is 42,720 feet or 8.09 miles.

Actual gas loss will be calculated after purge has been completed, then entered in the Maximo system.

♦ Mandatory Data Collection & Submission Requirements:

All Gas Loss associated with blow and purge down activities must be recorded and entered into Maximo.

Actual Plan Readings for Segment from Walbridge VS to Peach Orchard VS:

Blow-down Procedure:

- Time Blow-down started: 9:35 AM
- Time Blow-down ended: 10:35 AM
- Date of Blow-down: 9-8-10
- Line Pressure prior to blow-down: 198 lbs.
- % Gas Reading: 0%
- Taken by: Doug Wagner
- Time Reading Taken: 10:40
- Instrument Model and Serial Number: 60 - 4108

Purge:

1. Gas reading prior to purge:

- % Gas Reading: 0%
- Taken by: 2:25
- Time Reading Taken: Doug Wagner
- Instrument Model and Serial Number: 60 - 4108

2. Purge Procedure:

- Time Purge started: 8:30 PM
- Time Purge ended: 10:30 PM
- % Gas Reading at end of purge: 96.0%
- Reading taken by: Doug Wagner
- Instrument Model and Serial Number: 60 - 5363

Summary of Gas Lost

	<u>Estimated</u>	<u>Actual</u>
Blow down	1352 MSCF	_____ MSCF
Purge	117 MSCF	_____ MSCF
TOTAL GAS LOST	1469 MSCF	_____ MSCF

NOTE:

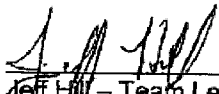
Please note...the above blow down/purge plan is tentative. This procedure could change as construction sequences are modified or other unanticipated variables develop. If changes are required, these changes are to be noted on this plan, initialed and a copy forwarded to Steve Bellini (304-465-6428) in the St. Albans, West Virginia office.

Submitted By: James Bowling
Energy Management & Services (EMS)
Telephone: 859-753-8500

Reviewed By:

Steve Bellini – Pipeline Engineer
Columbia Gas Transmission
304-722-8657

Approved By:



Jeff Hill – Team Leader
Columbia Gas Transmission
606-478-6303

The information on this document shall be used only for the designated project. This document is in an electronic format that can be altered by the user. Any reuse of the data that has been altered or modified will be at the user's sole risk without liability or legal exposure to Energy Management & Services Co., who will not be responsible for the deterioration or defects in the data after 45 days following the transmittal date.

Lock Out / Tag Out Checklist

- Review Lock-out/Tag-out (LOTO) procedures outlined in PP&P 110.01.10 during all valve operations.

Blow Down Procedure

- Producer Meters

		<u>Locked By</u>	<u>Date</u>	<u>Time</u>
<input checked="" type="checkbox"/> ○	Hay Explor. – MS19455 – Inv. Sta. 2147+17 LOTO sideline valve, unnumbered	<u>JC</u>	<u>9-8-10</u>	<u>5:15am</u>
<input checked="" type="checkbox"/> ○	Hay Explor. – MS30586 – Inv.Sta. 1971+88 LOTO sideline valve, unnumbered	<u>JC</u>	<u>9-8-10</u>	<u>5:30am</u>
<input checked="" type="checkbox"/> ○	Badien Gas – MS27566 – Inv. Sta. 1937+83 LOTO sideline valve, unnumbered	<u>JC</u>	<u>9-8-10</u>	<u>6:15am</u>

- Peach Orchard Valve Setting– 1859+95

<input checked="" type="checkbox"/> ○	Mainline Valve, P-215	<u>DN</u>	<u>9/8/10</u>	<u>8:30am</u>
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- Walbridge Valve Setting – 2280+65

<input checked="" type="checkbox"/> ○	Mainline Valve, P-240	<u>DT</u>	<u>9/8-10</u>	<u>8:00AM</u>
<input checked="" type="checkbox"/> ○	Sideline Valve, P-243	<u>DT</u>	<u>9/8/10</u>	<u>8:00AM</u>
<input checked="" type="checkbox"/> ○	Blow-off Valve, P-242	<u>DT</u>	<u>9/8/10</u>	<u>8:00AM</u>

Attachment A

PLAN NUMBER: 110.01.06 VERSION NUMBER: 2

Safety Requirements for Operations Involving Hydrogen Sulfide (H2S)

3.2 Monitoring Requirements

1. Whenever an employee is working in an area where the potential for exposure to H2S exists, a means of continuous monitoring for this toxic gas is required.
 - a. Personal, portable monitors are suitable for activities such as well gauging and inspection, line repair, and blowdown.
 - 1) Portable monitors must have a range up to 100 ppm, respond rapidly, and emit an audible alarm at 10 ppm of H2S in air.
 - b. Fixed monitors with multi-sensor probes are suitable for drilling and well workover operations (see Section 3.2.3).
 - c. Continuing work in atmospheres where the H2S exceeds 10 ppm is forbidden unless self-contained breathing units are used.
2. A minimum of two portable personal monitors are recommended on drilling sites to supplement fixed units by compensating for changing air currents and employee movements about the site.
3. Lead acetate paper or ampoules and detector tubes are not acceptable means of monitoring H2S. Detector tubes can be used to measure H2S concentration levels in the air if the employee wears a self-contained breathing unit during the testing.
 - a. Detector tubes can be used to measure sulfur dioxide SO2 evolved when H2S is vented and flared off.
 - b. Workers are not to be exposed to levels of (SO2) in excess of 5 ppm by volume (13 mg/m3).

3.4 Required Practices for Operations, Other than Drilling/Well Workers Where H2S Exposure is Suspected

1. Facilities such as pipelines, meters, regulators, sulfur-removal units, and production storage wells which are identified by region or department supervision as transporting or containing H2S must be posted with "Danger – Poisonous Gas – H2S" signs to alert employees of the hazard.
2. Operations and maintenance activities on facilities which would involve exposure to H2S (i.e., blowdown of lines of equipment containing sour gas) require the use of continuous operating, portable H2S detector.
 - a. The portable detector audibly alerts employees when the H2S concentration in air reaches 10 ppm. Upon reaching 10 ppm H2S, the employee must either leave the area and allow natural or mechanical ventilation to reduce the level or continue work using self-contained breathing unit.

Attachment B

SPECIFICATION OEP-102

USE OF AIR MOVERS WHEN CUTTING AND WELDING

I. GENERAL

Air movers are used to eliminate fire hazards when performing necessary cutting and welding operations. The air mover, when attached to the pipeline, can be used to successfully evacuate the pipeline of a combustible mixture.

II. PRINCIPLE OF OPERATION OF AN AIR MOVER

Figure 1 below diagrams an air mover. Compressed "gas" or "air" is fed into the air mover through a side connection (A) at the bell end. Either air or natural gas can be used in the side connection. The bell housing (B) has an outlet that allows the supply "gas" or "air" to exit from the bell in the direction of the "horn" (C) only. The bell housing forms an efficient venturi with the annular orifice (D) located in the throat (E) of the venture. Supply gas enters the bell under pressure and expands through the annular orifice in the venture throat. This expansion produces a sharp drop in pressure in the throat of the venturi. The decreased pressure draws large volumes of air or line gas into the bell from the outside. The induced air or line gas joins with the supply gas or air and both are forced out through the horn.

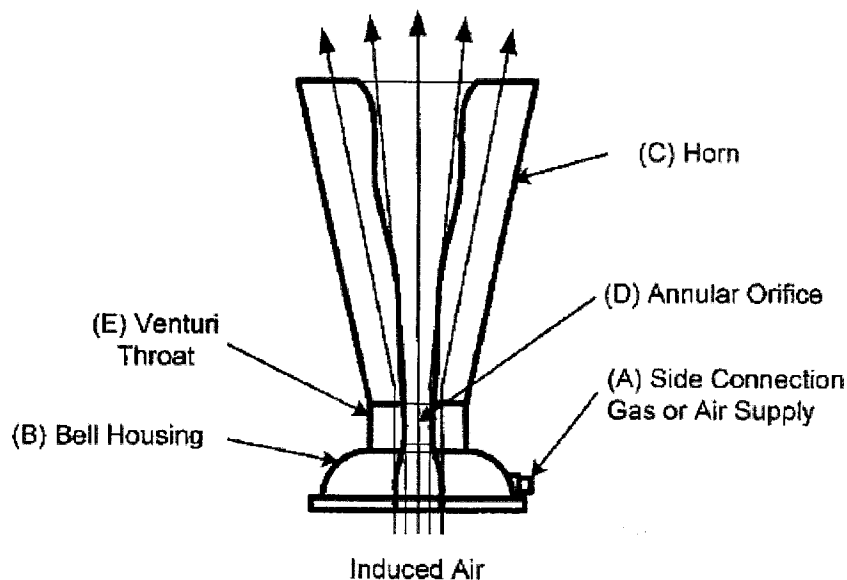


Figure 1

III. INSTALLATION OF AIR MOVER

A. Scope

The air mover use for three common types of tie-ins will be discussed to show how to control the atmosphere in the area where welders must perform their jobs. In all cases, it will be assumed that the section to be cut has been depressurized, the main block valves do not leak excessively, and the air movers have been attached on the blow-off valves that are located on both ends of the depressurized

section. It is also assumed that if a down draft occurred at either or both of the blow-off valves at the completion of the blow-down, the blow-off valve was closed to keep air out of the depressed section.

ONLY TRAINED PERSONNEL SHOULD INSTALL AND OPERATE AIR MOVERS

NOTE: THE AIR MOVER MUST BE GROUNDED TO AVOID ANY POSSIBILITY OF A BUILD-UP OF STATIC ELECTRICITY DURING OPERATION, ESPECIALLY IN CASES OF SUST OR TUST PARTICLES IN THE GAS

B. Sizes

Lamb air movers are available in three sizes – 3", 6" and 10".

The 3" size will exactly fit a 4" standard ASA 300 or 600 series valve flange and can be adapted to a 2" or 3" size. The 6" size exactly fits a standard 6" valve flange and can be adapted to an 8" valve. The 10" size air mover can be adapted to a 10" or 12" valve flange.

C. Set Up of Air Mover

Figure 2 shows the set up and arrangement of the air mover and associated equipment. This equipment is installed after blow-down. A pressure gauge is installed at the bell so that an accurate check on supply gas or air pressures can be maintained. The supply control valve is a 1" high-pressure gate valve that precludes a large pressure drop through it if the source of supply air or gas is low. The supply air or gas is fed to the control valve by a ¾" I.D. high-pressure flexible hose. Quick couplers are supplied so that the connection can be put on or taken off with little loss of time. The air mover is fastened to the flange of the blow-off valve with 3-6" "C" clamps, using a soft rubber gasket as a seal.

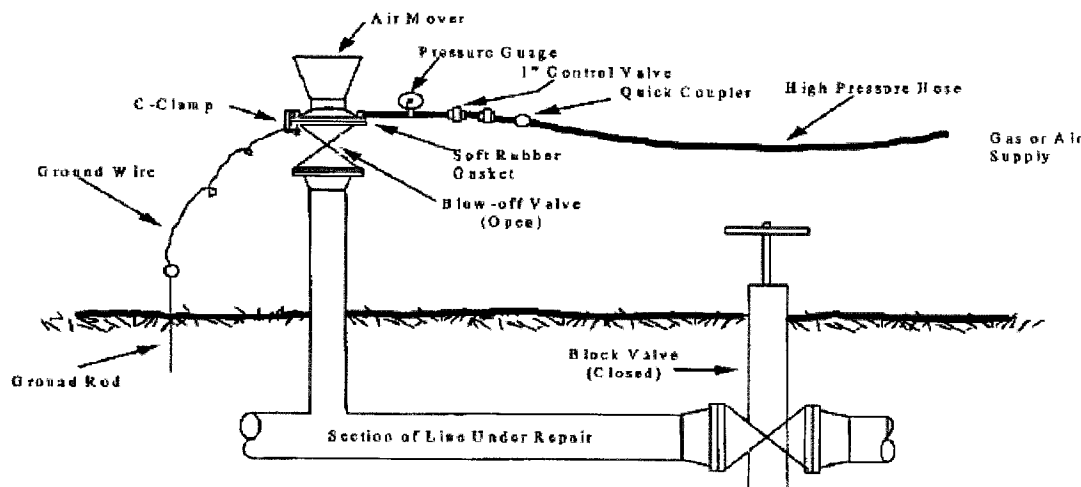


Fig. 2

D. Supply Air or Natural Gas

Supply to the air mover can be either air or natural gas. An air compressor that is capable of producing 300 C.F.M. at 90 psig is large enough to supply the 3" and 6" air movers. **Maximum pressure for a 6" air mover is 70 psig.** The 10" size will require an air compressor capable of producing a maximum of 400 C.F.M. at 90 psig.

In most cases, the readily available source of natural gas can be used as a supply to the air mover. For instance, when the air mover is mounted on a blow-off after blow-down, supply gas may be available

on the other side of the main block valve. If the supply gas is sufficiently "wet" so that hydrates may form at the point of regulation, an alcohol drip must be supplied in order to keep the air mover control valve free of ice. An alcohol drip bottle can be installed as shown in Figure 3. It has been found through experience that the alcohol drip is not necessary for gas with a water content less than 7lb/MMcf.

V. PROCEDURES FOR USE OF AIR MOVERS DURING TIE-IN OF A LINE REPLACEMENT

This case involves tie-in for a relocation of an existing line for any reason. The two tie-in points are too far apart to handle with one tie-in operation or in one bell hole. A diagram of this operation is shown in Figure 6.

1. Isolate and blow down section of line to be cut. If downdraft occurs at blow-off, close the blow-off.
2. Mount air movers on each blow-off, and make ready for operation. **MAKE SURE THE AIR MOVERS ARE GROUNDED.**
3. Cut or grind out a small elliptical test hole at Job site II, as described in IV – 3 above.

An access hole is cut as previously described (See Section III, Step 1). This access hole is cut at the point where the work is to be completed first or, in the interest of saving time, at the point which promises to be the most difficult. It will be assumed for this discussion that this access hole is cut at Job I (See Figure 6).

Fire extinguishers shall be at the job site, and manned during all cutting operations.

4. Before or during the cutting of the access hole at Job I, a small test hole about the size of a dime is cut into the top of the pipe at Job II, in the section of pipe to be cut out of the line. As soon as this small hole is cut, the fire is extinguished and a patch of plastic tape is applied over the hole. This small test hole will be used later for testing with an approved gas detector

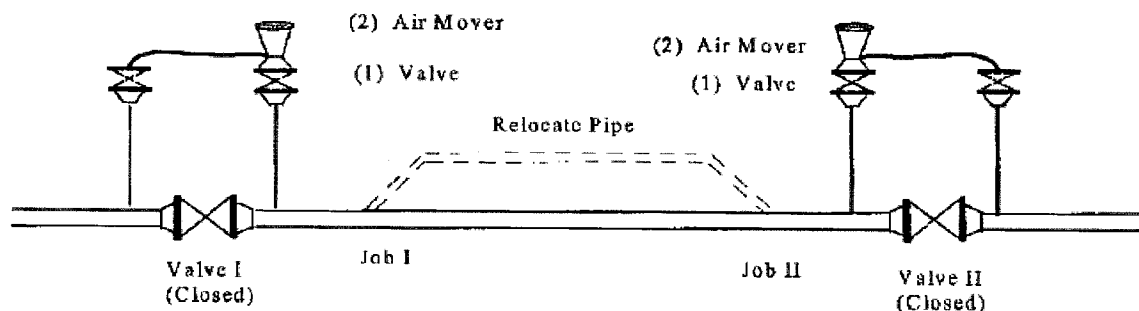


FIGURE 6

5. Start air movers and adjust pressure to the air movers so the air enters the test hole at Job Site 1 and moves towards BOTH air movers.

Proceed with Steps 5 through 9 as outlined in Section IV.

After testing for presence of gas in the access hole at Job I, and properly adjusting the airflow rates, construction at Job I may continue in the usual manner.

6. Proceed with large access hole at Job I location as outlined in Step 10, Section IV.
7. After first short pup has been cut out (Job I), or when an open end at Job I in the direction of Job II has been achieved, the air mover (2) at Valve II can be turned up to its maximum evacuation rate. This helps to remove the air and gas mixture in the line between the two tie-in locations.
8. Remove tape from small hole at the second location (Job II) and test for safe atmosphere in the line along the top, midway and bottom of pipe. If the mixture is found to be below the lower explosive limit, cutting may proceed. If not, the hole should be retaped and the gas detector tests run about every two minutes until a safe mixture is found at Job II.
9. When a safe condition is found to be present, clear all personnel from the open end of the pipe at the first location (Job I).

IMPORTANT: Before the cutting commences at Job II, all personnel must be cleared from the open end of the line at Job I. This is a safety precaution taken to avoid injury in the event of flash back through the pipe.

Fire extinguishers shall be at the job site, and manned during all cutting operations.

10. Start cutting line at second location (Job II).
11. After the cut is made at the second location (Job II) work can be resumed at the first location (Job I).
12. Complete all cutting and welding at both locations.

As the lineup at Job II approaches completion, the supply pressure at both air movers (2) must be reduced in order to reduce the air flow in the line to a minimum. This can be accomplished by slowly closing the supply control valve on the bell of the air movers (2). Make certain, however, that a slight updraft is maintained at both air movers (2), keeping the air-gas mixture moving away from the two jobs, and yet, not subjecting the hot stringer bead to the effect of a vacuum inside the line. The condition of slight updraft should be held at each air mover until both welds have received their hot passes.

13. Shut down and remove air movers.

After both hot passes are complete, the blow-off valves under each air mover may be closed and the source of supply to each air mover (2) may be shut off. The air movers may then be removed from service.

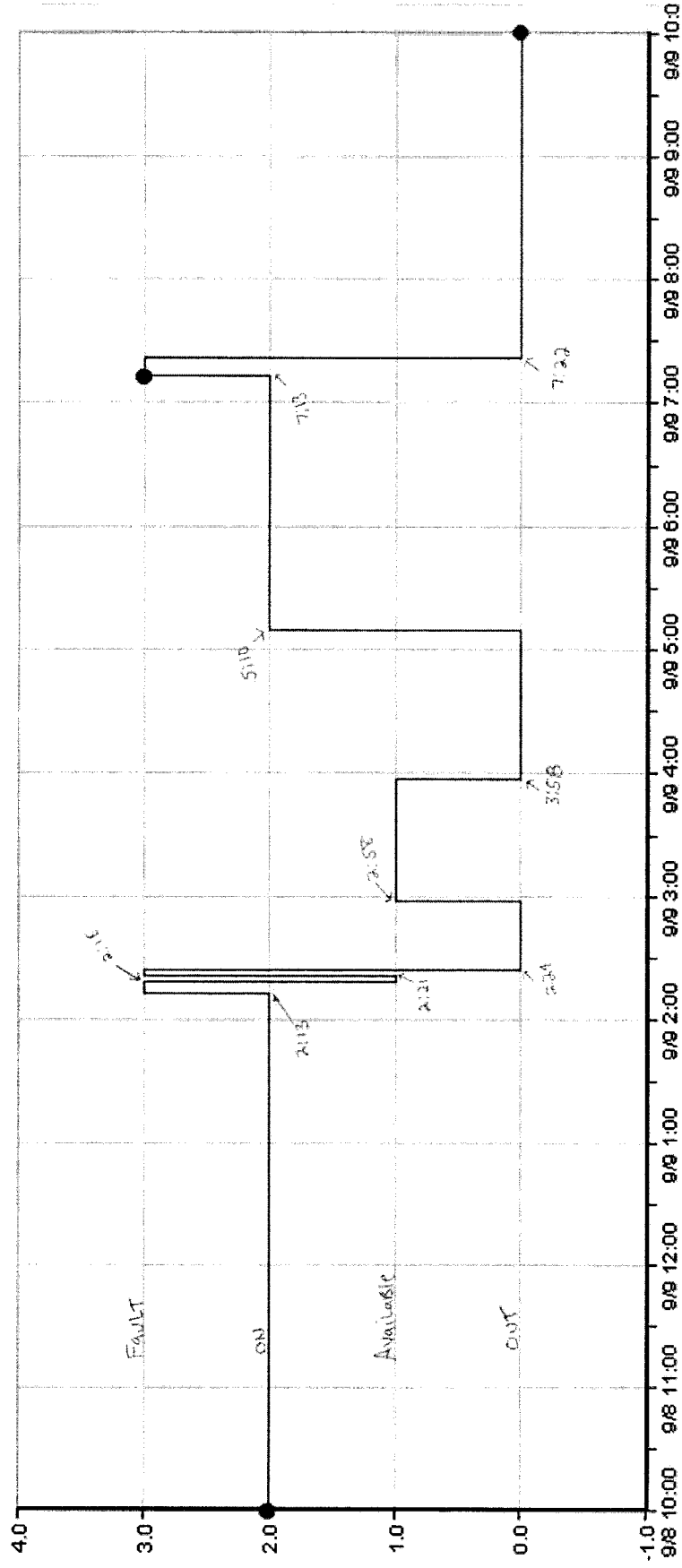
14. Purge.

Appendix C

Kenova Engine Status Charts



Kenova Engines



Bottom

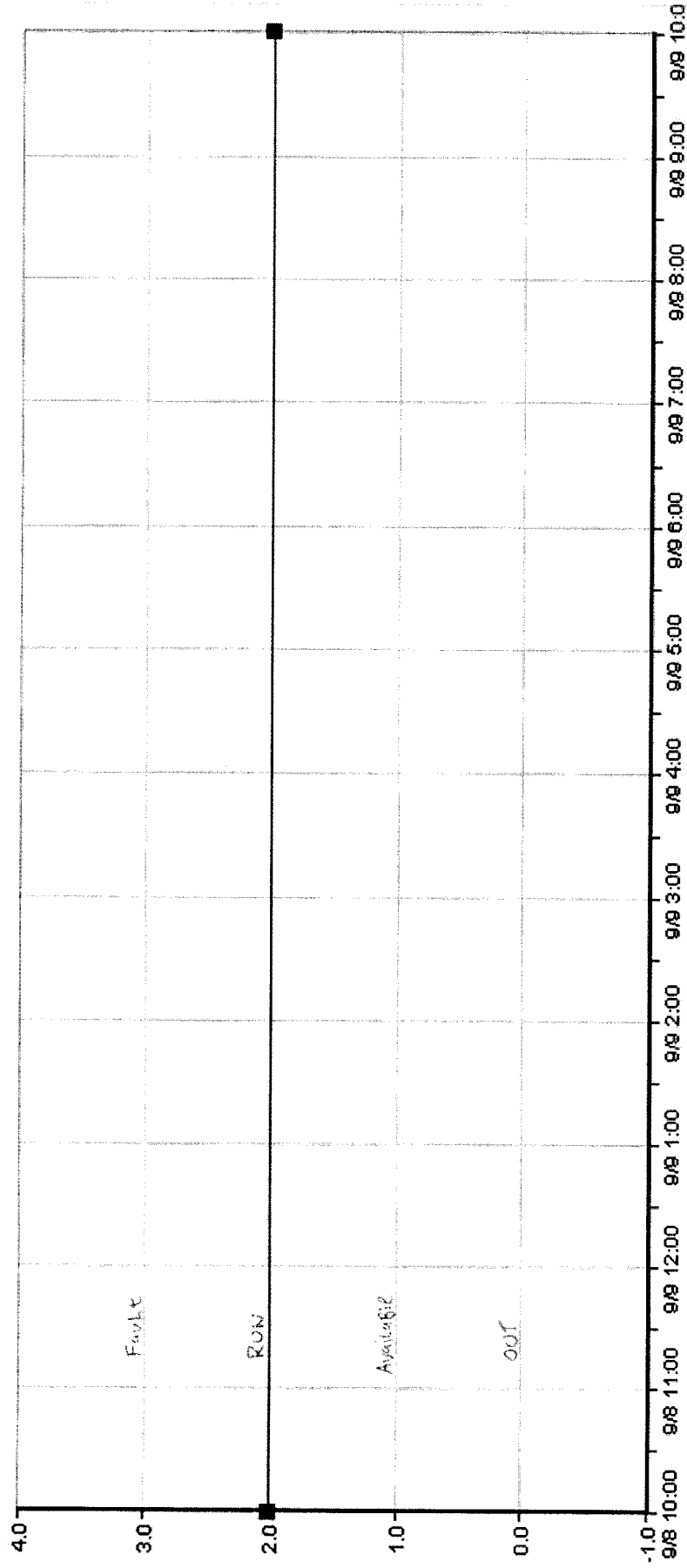
● Kenova CS Unit1 Engine Status

Engine 1 Low

0.00 Out



Kenova Engines

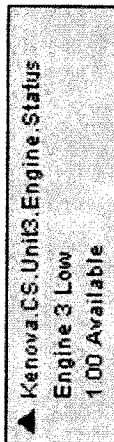


Bottom

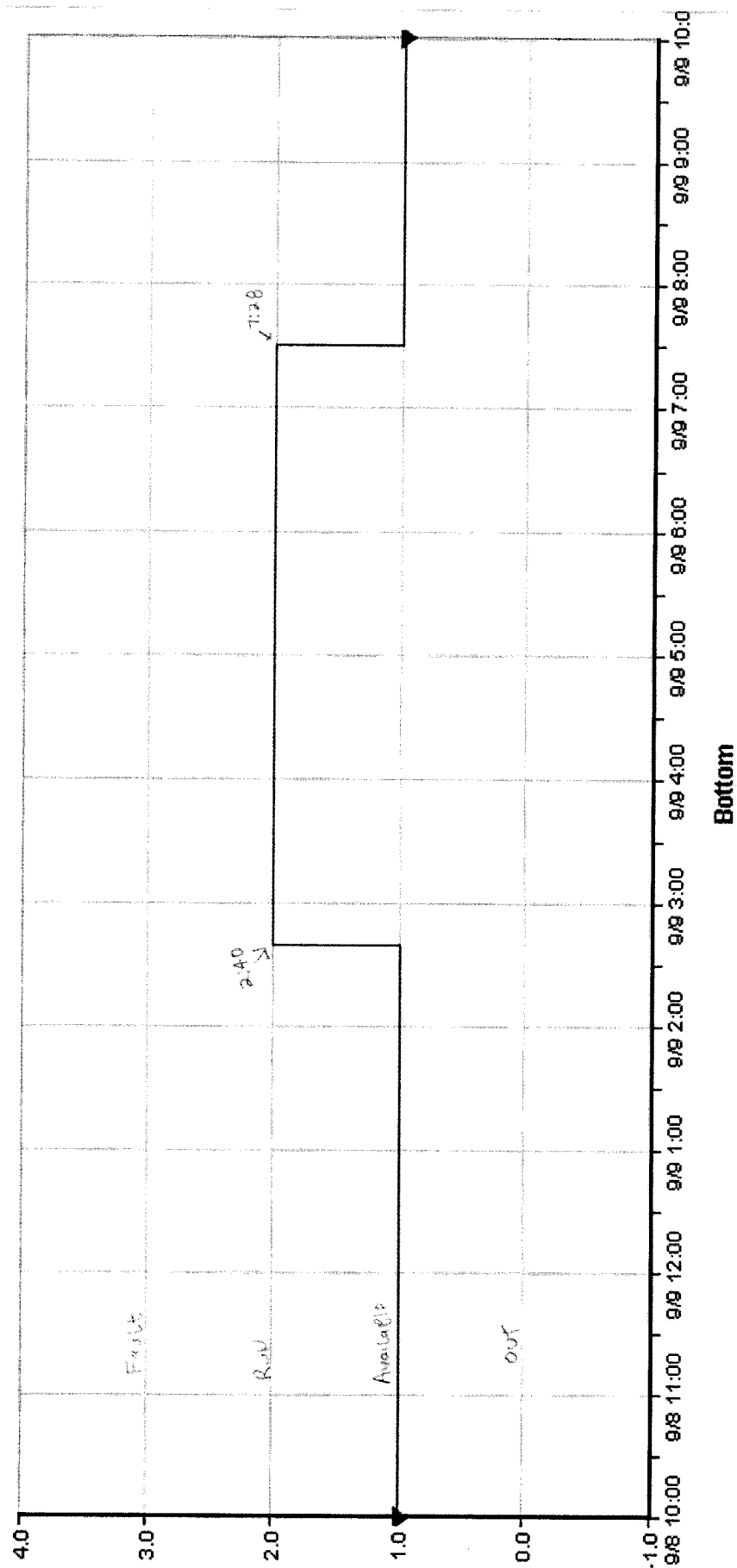
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Kenova CS.Unit2.Engine.Status
Engine 2 Low
2.00 Run

1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012, 2013, 2014, 2015, 2016, 2017, 2018, 2019, 2020, 2021, 2022, 2023, 2024, 2025, 2026, 2027, 2028, 2029, 2030, 2031, 2032, 2033, 2034, 2035, 2036, 2037, 2038, 2039, 2040, 2041, 2042, 2043, 2044, 2045, 2046, 2047, 2048, 2049, 2050, 2051, 2052, 2053, 2054, 2055, 2056, 2057, 2058, 2059, 2060, 2061, 2062, 2063, 2064, 2065, 2066, 2067, 2068, 2069, 2070, 2071, 2072, 2073, 2074, 2075, 2076, 2077, 2078, 2079, 2080, 2081, 2082, 2083, 2084, 2085, 2086, 2087, 2088, 2089, 2090, 2091, 2092, 2093, 2094, 2095, 2096, 2097, 2098, 2099, 2100, 2101, 2102, 2103, 2104, 2105, 2106, 2107, 2108, 2109, 2110, 2111, 2112, 2113, 2114, 2115, 2116, 2117, 2118, 2119, 2120, 2121, 2122, 2123, 2124, 2125, 2126, 2127, 2128, 2129, 2130, 2131, 2132, 2133, 2134, 2135, 2136, 2137, 2138, 2139, 2140, 2141, 2142, 2143, 2144, 2145, 2146, 2147, 2148, 2149, 2150, 2151, 2152, 2153, 2154, 2155, 2156, 2157, 2158, 2159, 2160, 2161, 2162, 2163, 2164, 2165, 2166, 2167, 2168, 2169, 2170, 2171, 2172, 2173, 2174, 2175, 2176, 2177, 2178, 2179, 2180, 2181, 2182, 2183, 2184, 2185, 2186, 2187, 2188, 2189, 2190, 2191, 2192, 2193, 2194, 2195, 2196, 2197, 2198, 2199, 2200, 2201, 2202, 2203, 2204, 2205, 2206, 2207, 2208, 2209, 2210, 2211, 2212, 2213, 2214, 2215, 2216, 2217, 2218, 2219, 2220, 2221, 2222, 2223, 2224, 2225, 2226, 2227, 2228, 2229, 2230, 2231, 2232, 2233, 2234, 2235, 2236, 2237, 2238, 2239, 2240, 2241, 2242, 2243, 2244, 2245, 2246, 2247, 2248, 2249, 2250, 2251, 2252, 2253, 2254, 2255, 2256, 2257, 2258, 2259, 2260, 2261, 2262, 2263, 2264, 2265, 2266, 2267, 2268, 2269, 2270, 2271, 2272, 2273, 2274, 2275, 2276, 2277, 2278, 2279, 2280, 2281, 2282, 2283, 2284, 2285, 2286, 2287, 2288, 2289, 2290, 2291, 2292, 2293, 2294, 2295, 2296, 2297, 2298, 2299, 2300, 2301, 2302, 2303, 2304, 2305, 2306, 2307, 2308, 2309, 2310, 2311, 2312, 2313, 2314, 2315, 2316, 2317, 2318, 2319, 2320, 2321, 2322, 2323, 2324, 2325, 2326, 2327, 2328, 2329, 2330, 2331, 2332, 2333, 2334, 2335, 2336, 2337, 2338, 2339, 2340, 2341, 2342, 2343, 2344, 2345, 2346, 2347, 2348, 2349, 2350, 2351, 2352, 2353, 2354, 2355, 2356, 2357, 2358, 2359, 2360, 2361, 2362, 2363, 2364, 2365, 2366, 2367, 2368, 2369, 2370, 2371, 2372, 2373, 2374, 2375, 2376, 2377, 2378, 2379, 2380, 2381, 2382, 2383, 2384, 2385, 2386, 2387, 2388, 2389, 2390, 2391, 2392, 2393, 2394, 2395, 2396, 2397, 2398, 2399, 2400, 2401, 2402, 2403, 2404, 2405, 2406, 2407, 2408, 2409, 2410, 2411, 2412, 2413, 2414, 2415, 2416, 2417, 2418, 2419, 2420, 2421, 2422, 2423, 2424, 2425, 2426, 2427, 2428, 2429, 2430, 2431, 2432, 2433, 2434, 2435, 2436, 2437, 2438, 2439, 2440, 2441, 2442, 2443, 2444, 2445, 2446, 2447, 2448, 2449, 2450, 2451, 2452, 2453, 2454, 2455, 2456, 2457, 2458, 2459, 2460, 2461, 2462, 2463, 2464, 2465, 2466, 2467, 2468, 2469, 2470, 2471, 2472, 2473, 2474, 2475, 2476, 2477, 2478, 2479, 2480, 2481, 2482, 2483, 2484, 2485, 2486, 2487, 2488, 2489, 2490, 2491, 2492, 2493, 2494, 2495, 2496, 2497, 2498, 2499, 2500, 2501, 2502, 2503, 2504, 2505, 2506, 2507, 2508, 2509, 2510, 2511, 2512, 2513, 2514, 2515, 2516, 2517, 2518, 2519, 2520, 2521, 2522, 2523, 2524, 2525, 2526, 2527, 2528, 2529, 2530, 2531, 2532, 2533, 2534, 2535, 2536, 2537, 2538, 2539, 2540, 2541, 2542, 2543, 2544, 2545, 2546, 2547, 2548, 2549, 2550, 2551, 2552, 2553, 2554, 2555, 2556, 2557, 2558, 2559, 2560, 2561, 2562, 2563, 2564, 2565, 2566, 2567, 2568, 2569, 2570, 2571, 2572, 2573, 2574, 2575, 2576, 2577, 2578, 2579, 2580, 2581, 2582, 2583, 2584, 2585, 2586, 2587, 2588, 2589, 2590, 2591, 2592, 2593, 2594, 2595, 2596, 2597, 2598, 2599, 2600, 2601, 2602, 2603, 2604, 2605, 2606, 2607, 2608, 2609, 2610, 2611, 2612, 2613, 2614, 2615, 2616, 2617, 2618, 2619, 2620, 2621, 2622, 2623, 2624, 2625, 2626, 2627, 2628, 2629, 2630, 2631, 2632, 2633, 2634, 2635, 2636, 2637, 2638, 2639, 2640, 2641, 2642, 2643, 2644, 2645, 2646, 2647, 2648, 2649, 2650, 2651, 2652, 2653, 2654, 2655, 2656, 2657, 2658, 2659, 2660, 2661, 2662, 2663, 2664, 2665, 2666, 2667, 2668, 2669, 2670, 2671, 2672, 2673, 2674, 2675, 2676, 2677, 2678, 26

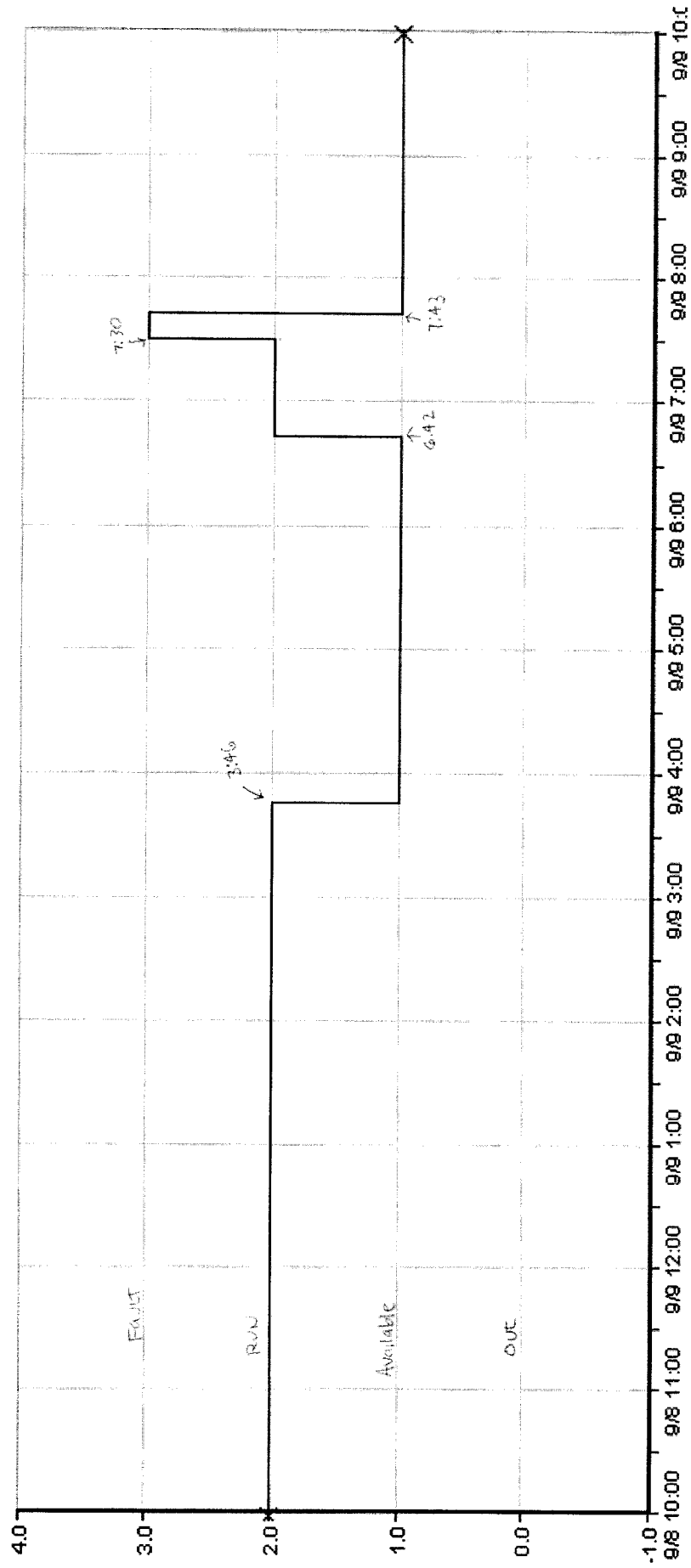


1



▼ Kenova CS Unit 4 Engine Status
Engine 4 Low
1.00 Available

Kenova Engines

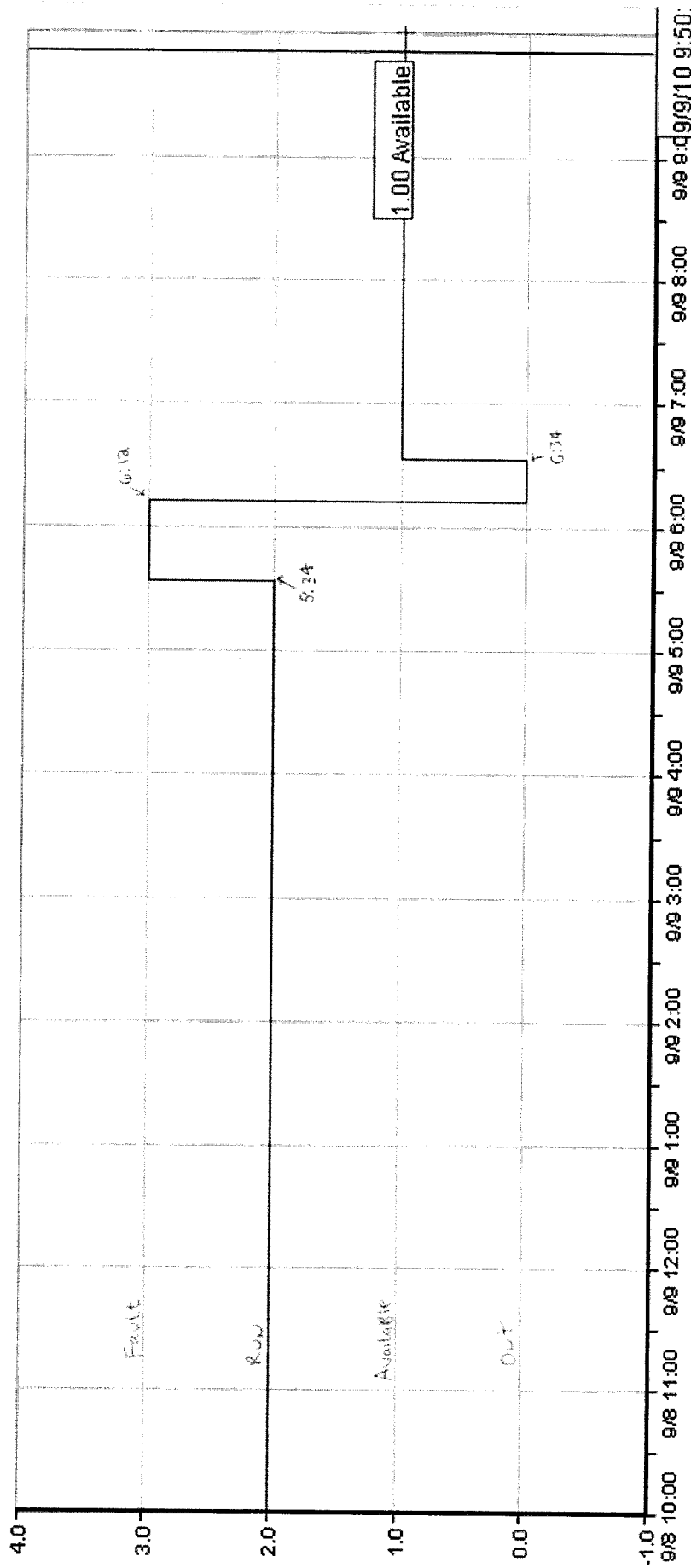


Bottom

X Kenova.CS.Unit5.Engine.Status
Engine 5 High
1.00 Available



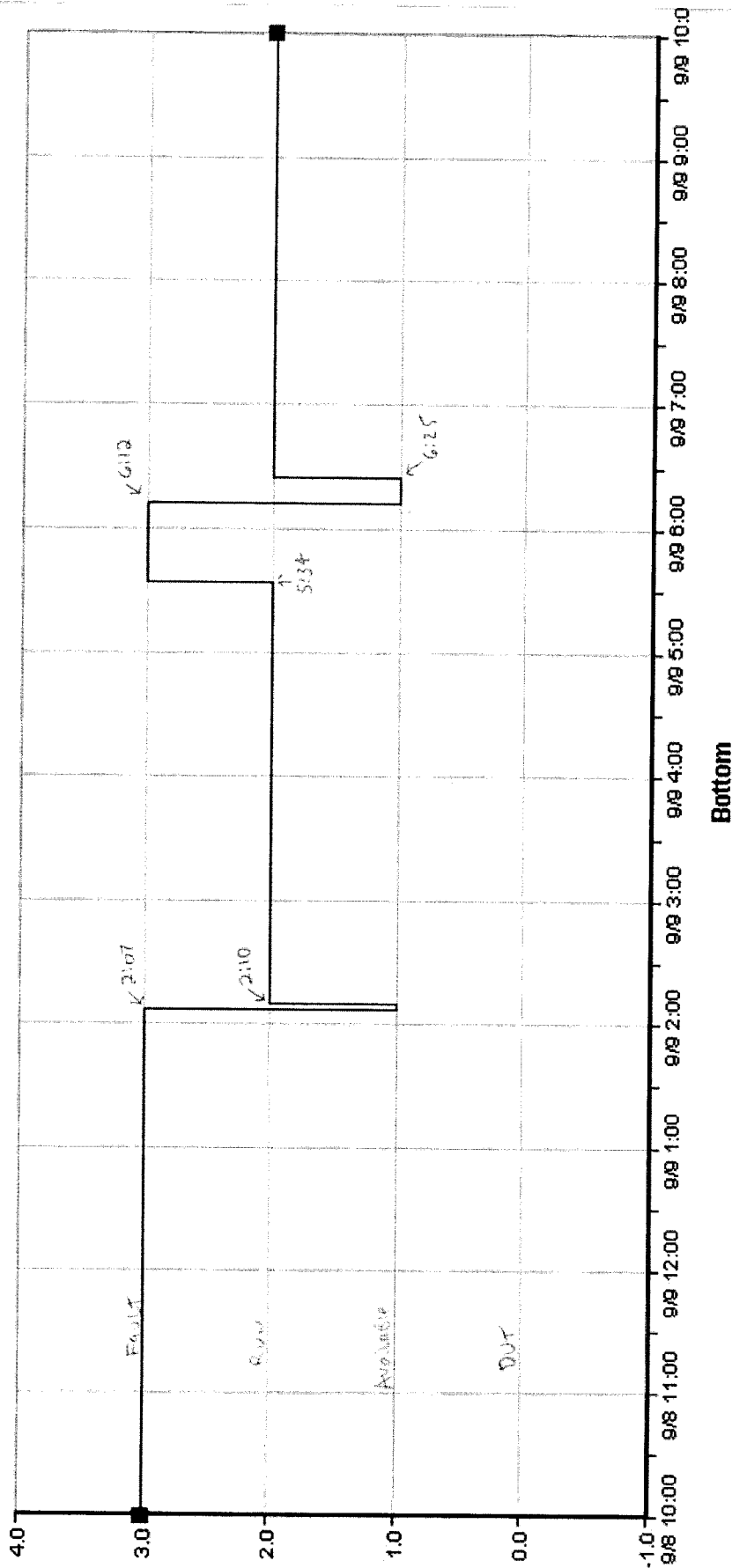
Kenova Engines



Bottom

+ Kenova CS Unit#6 Engine Status
Engine #6 High
1.00 Available

Kenova Engines



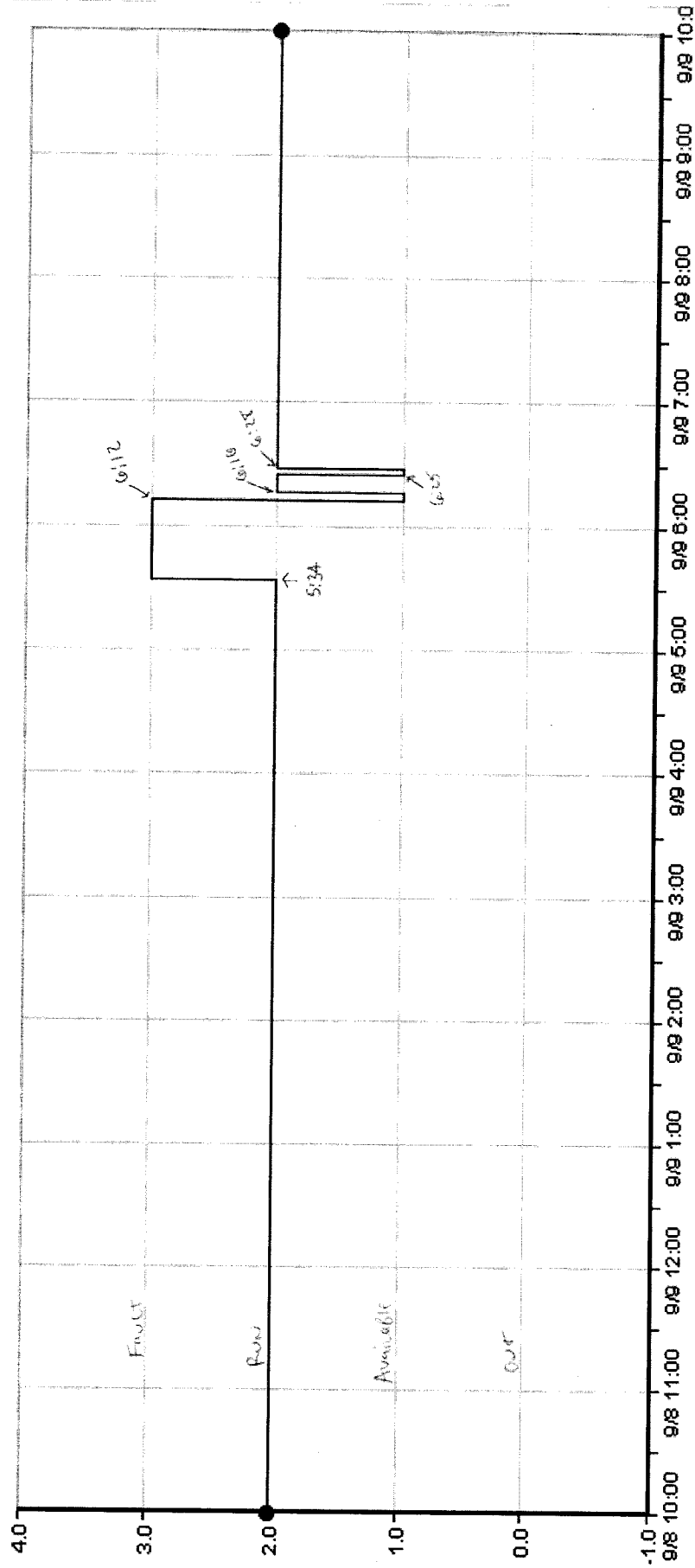
Kenova.CS.Unit7.Engine.Status

Engine 7 High

2.00 Run



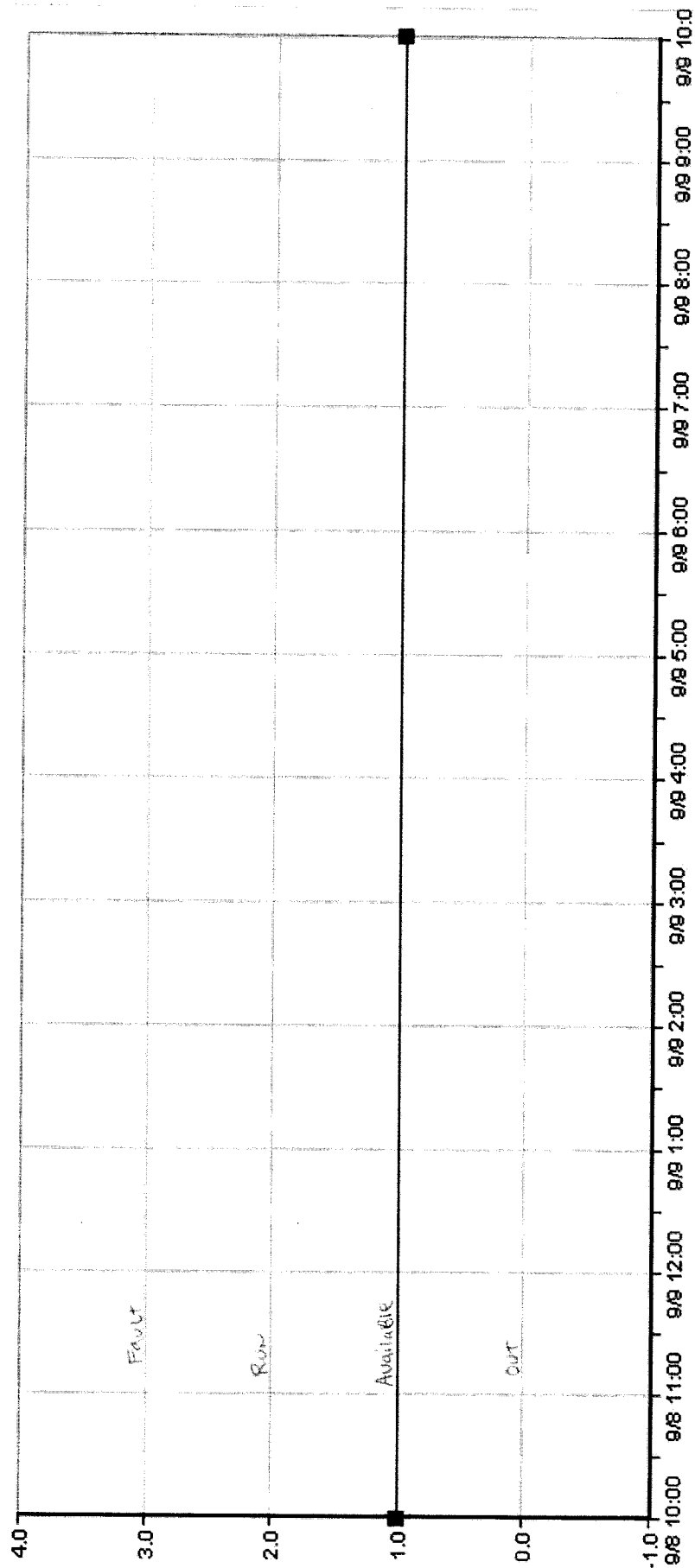
Kenova Engines



Bottom



Kenova Engines



Bottom

■ Kenova.CS.Unit@ Engine Status
Engine @ High
1.00 Available

Attachment 2

Line P - Bare Pipe Replacement Work Plan

Overview

The remaining bare pipe located along Line P will be replaced with new coated and welded line pipe. The replacement will consist of replacing approximately 63,295 feet of pipe. The remaining bare pipe is located between Chestnut Junction and Walbridge Compressor Station. There are short sections of coated and welded pipe located between Chestnut Junction and Walbridge Station that do not require replacement, and there are several coated sections that will be replaced due to ease of construction or to achieve a common pipe size in order to facilitate future integrity assessment.

Milestones

The following milestone elements of work are scheduled to be completed as a part of this work plan. The completion dates are current estimates and are subject to change.

Engineering

Engineering has already commenced for the replacement of the remaining bare pipe along Line P. A disciplined process is followed, referred to as the Gates Process. Gate 2, which involves a 30% design review, is scheduled for completion by December 17, 2010. Gate 3, which includes a 70% design review, is scheduled for completion by March 8, 2011. Gate 4, which involves the issuing of engineering design for construction, is scheduled for completion by May 4, 2011.

Pipe Procurement and Manufacture

A bidding process was completed and a pipe purchase order was issued to US Steel on October 25, 2010. A summary of the pipe order is provided below:

- 63,944 feet of 20" OD, 0.250" WT API 5L PLS2 X65 line pipe coated with Fusion Bonded Epoxy (FBE) for mainline pipe replacement at a purchase cost of \$2,470,797.
- 1,000 feet of 20" OD, 0.375" WT API 5L PLS2 X42 line pipe coated with FBE and Abrasion Resistant Overcoat (ARO) for road crossing replacement at a purchase cost of \$83,850.

Pipe manufacturing is scheduled to be complete prior to December 31, 2010. Pipe coating and delivery is scheduled for completion prior to January 28, 2011.

Landowner Notification, Acquisition and Right of Way Preparation

Landowner notification, acquisition and right of way preparation is scheduled to begin on November 1, 2010 and is planned for completion by April 1, 2011.

Survey

Survey of the pipeline route for permitting and construction is scheduled to begin on December 1, 2010, and is planned for completion by February 10, 2011.

Environmental Permitting

Acquisition of environmental permits required for construction will begin in December 2010 and is planned for completion by April 26, 2011.

Line P – Bare Pipe Replacement Work Plan

Construction and Testing

Construction is scheduled to begin on June 1, 2011 and is planned for completion by August 15, 2011. Pressure testing and dewatering is planned for completion by August 31, 2011, at which time the pipeline will be returned to service. Final cleanup and right of way restoration is planned for completion by September 6, 2011.

Project Close-Out

Final as-builts and project completion reports are planned for completion by September 20, 2011.

Replacement Sections

The segments listed below represent the pipe sections that will be replaced. Once completed, Line P will consist entirely of coated and welded pipe.

Begin Station	End Station	Length (ft)
1480+26	1741+68	26,142
1751+20	1768+36	1,716
1786+78	1854+59	6,362
1860+16	2150+91	29,075
	Total	63,295

New Pipe Specifications

The specification for the new pipe that will be purchased and installed as replacement for the remaining bare pipe along Line P is as follows:

- 63,944 feet of 20" OD, 0.250" WT API 5L PLS2 X65 line pipe coated with Fusion Bonded Epoxy (FBE) for mainline pipe replacement.
- 1,000 feet of 20" OD, 0.375" WT API 5L PLS2 X42 line pipe coated with FBE and Abrasion Resistant Overcoat (ARO) for road crossing replacement.

Project Management / Point of Contact

The project manager and primary point of contact for field construction activities will be:

Ted Smith
ctsmith@nisource.com
304-357-3211 office
304-549-3212 cell